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ENERGY REGULATORS REGIONAL ASSOCIATION

Tariff/Pricing Committee



## ISSUE PAPERS

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# Introduction

*Dear Ladies and Gentleman:*

The Tariff/Pricing Committee was established in December 1998 as a part of the Energy Regulators Regional Association (established by NARUC in cooperation with US Agency for International Development). In December 2000, the Committee was officially approved as one of the two ERRA standing committees.

In the period from 1999 to 2003, the Committee has reviewed 17 topics. They were formulated taking into account wishes and priority objectives of the regulatory organizations from member countries. The process of reforms in these countries is at different phases, therefore, for some countries the issues considered under these topics are current problems requiring immediate solution, while for the other countries they represent pending problems that these countries will have to resolve in the framework of future reforms. Irrespective of that, all considered topics are of certain value and are directly related to main functions of the regulatory organizations.

Cooperation within the framework of the Committee, as well as exchange of experience and views of regulators on various topics that are of mutual interest, promotes better efficiency of their work, helps to improve professional skills and to cope with complex problems they are facing in the course of regulating their energy sectors.

I would like to express my gratitude to all Committee members for their creative contribution in the work of the Committee; I also want to thank US Agency for International Development, NARUC and ERRA for their comprehensive assistance, support and valuable suggestions.

I hope that our fruitful cooperation will continue in future and would be provide valuable assistance in the process of our countries' transition to free market economies.

Sincerely:



*Florin Gugu*

Chairman of the Tariff/Pricing Committee

Commissioner, National Electricity and Heat Regulatory Commission of Romania

# Issues in the Determination of Tariffs for Ancillary Services

Prepared by Sandra Waldstein, Vermont Public Service Board (USA), and  
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**Abstract:** Part I will begin with a description of ancillary services and then go on to describe the types of ancillary services that are generally offered in the U.S. electric industry today. The pricing of ancillary services can be either market-based or through a regulated cost-of-service approach. In Part II, both types of pricing will be discussed in more detail. Some of the latest issues in the provision and pricing of ancillary services in the U.S. will be provided, as will some examples of prices and tariffs from U.S. markets. The paper will conclude with recommendations to consider when developing ancillary services within the ERRA region.

## **Part I**

### **A. Introduction**

Ancillary services can be thought of as those components of the overall energy product that are necessary to maintain the safe and reliable operation of the electric grid (transmission system).<sup>1</sup> These services include (1) regulation and frequency response, (2) reactive supply and voltage control, (3) scheduling, system operation control and dispatch, (4) energy imbalance service, (5) operating reserves, and (6) black start service. These ancillary services will be discussed in further detail below.

In most areas, the transmission system operator (TSO) is responsible for the reliable operation of the grid, thus the TSO has ultimate responsibility for ensuring that ancillary services are provided in the amount necessary to ensure safe and reliable operation. Because the TSO has ultimate responsibility for reliability, the TSO must be the provider of last resort for ancillary services. This is because a shortfall in any one of the ancillary services, such as an unexpected rise in load due to weather, or the failure of a generator or a transmission line, could lead to reliability problems on the grid.

Ancillary services are an important part of a comprehensive set of the products that originate from the generation of electricity. Like energy and capacity, they can be distinguished by their specific physical and operational characteristics. Because they are

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<sup>1</sup> The Federal Energy Regulatory Commission (FERC) defines such services as those "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."

provided by the same generation resources that supply energy and capacity, ancillary services are in many cases substitutes for energy and capacity. For this reason, many economists now believe that it is important to set the prices for these services separately so that each product – energy, capacity, and each ancillary service – reflects the true cost of providing that service. The value of ancillary services is significant. In the U.S., one estimate sets the nationwide cost of ancillary services at about \$12 billion per year or roughly 10% of the overall cost of the total energy commodity.<sup>2</sup>

In the past, ancillary services were included as part of the bundled set of services that utilities provided to their customers. The costs of ancillary services were typically included in the overall transmission tariff and not broken out by their individual components. But like energy and capacity, ancillary services can be unbundled from the total energy package. In other words, each ancillary service that will be described below can be identified and priced separately.

## **B. Types of Ancillary Services**

Unfortunately, there is not a consistent set of ancillary services that is agreed upon by everyone. There is further confusion since the terminology to describe similar services is used inconsistently. One author in the U.S. has identified twelve different ancillary services.<sup>3</sup> However, in Order No. 888, issued in 1996, the U.S. Federal Energy Regulatory Commission (FERC) required wholesale transmission providers to offer the following six ancillary services to their customers: (1) regulation and frequency response; (2) reactive supply and voltage control; (3) scheduling, system control and dispatch service; (4) energy imbalance service; (5) operating reserves – spinning; and (6) operating reserves – supplemental. Under Order 888, FERC required transmission owners to include these six ancillary services in their open access transmission tariffs.

Of these services, FERC has said that there are two services that are necessary to the basic provision of services within every control area. The TSO *must provide* these two ancillary services to all customers – (1) scheduling, system control and dispatch, and (2) reactive supply and voltage control. The TSO only has to *offer to provide* the following services to customers serving loads within the TSO control area: (1) regulation and frequency response; (2) energy imbalance service; (3) operating reserves – spinning; and (4) operating reserves – supplemental. For this latter group of services, the customer may self-provide the service or obtain the service through a bilateral arrangement if it so chooses.

FERC, in its proposed rule on Standard Market Design (SMD)<sup>4</sup>, further proposes that a regional transmission organization (RTO) provide bid-based markets for three of these services, (1) regulation, (2) spinning reserves, and (3) supplemental reserves. The price of these services would be determined based upon bids made into the market. Any customer that had not self-supplied or procured these services through a bilateral contract would be

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<sup>2</sup> <http://www.ehirst.com/ancillaryservices.htm>

<sup>3</sup> Hirst, Comments on Ancillary Services, FERC Docket No. RM99-2-00.

<sup>4</sup> The SMD proposed rule was issued on July 31, 2002, and is not yet final.

assessed a pro rata share of the costs incurred by the TSO for procuring those services in real time. This ruling is not yet final.

The list below includes all of the ancillary services identified by the FERC plus another ancillary service, black start service, which is a critical service for maintaining reliability.

1. Regulation and frequency response

This is an ancillary service that is recognized as necessary to meet engineering control performance standards to protect the safe and reliable operation of the electric grid. This type of ancillary service is also sometimes referred to as regulation, frequency response, or automatic generation control. This service is critical to reliable grid operation since system frequency can fluctuate greatly with short-term load fluctuations. In the U.S., a TSO must provide for the continuous balancing of resources so as to maintain a frequency at sixty cycles per second (60 Hz). The TSO must maintain this frequency standard and does so by utilizing generation resources that have automatic generation control (AGC) equipment installed. This makes those resources capable of raising or lowering of output instantaneously. Units that are capable of providing AGC are dispatched by the TSO, up or down as needed, to protect system reliability. Usually such units are certified as being capable of providing this service and must meet certain operational standards.

A transmission customer must either purchase this service from a transmission provider or make alternative comparable arrangements. Each customer has an obligation to provide a portion of regulation to the TSO and is assigned a share of the regulation requirement based upon its share of peak load. To meet this obligation, a customer can self-provide regulation if it owns generation, it can have bilateral contract arrangements to provide this service, or it can have the TSO make up any deficiency through other sources. Any customer that is deficient in providing regulation to the TSO is charged for the shortfall. Deficiency charges are based upon the costs of the units used to provide the service or upon market-based rates for AGC where markets have been developed for this product.

2. Reactive supply and voltage control

This is an ancillary service that must be provided by the TSO. This service is necessary to maintain the reactive power supply of the system or in other words, to maintain transmission voltages on the facilities within the TSO control area within acceptable limits. It is also referred to as reactive supply, reactive power, or voltage support. Voltage control is provided by reactive generation resources that are capable of producing (or absorbing) reactive power.<sup>5</sup> The amount of voltage control, or reactive power support, needed by the TSO is that amount necessary to

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<sup>5</sup> Various types of electrical equipment such as shunt capacitors, static var compensators, or synchronous condensers can be used to provide voltage support.

maintain transmission voltages within limits that are set for the region. In the U.S., an independent entity, the North American Reliability Council (NERC) sets these standards for each operational control area.

Voltage control is usually charged to all transmission customers based upon their energy usage or average hourly load within a particular load zone. All load in a zone is charged the same rate. The charge is based upon the costs of the reactive generation sources as filed at the FERC.

### 3. Scheduling, system operation control and dispatch

These are services that can only be performed by the TSO. The TSO, as the system control operator, must coordinate and implement all scheduling, system control, and dispatch of services for the relevant control area. Scheduling is the matching of generation and transmission resources to meet expected load. The TSO must maintain system reliability through accurate and complete scheduling of all system resources.<sup>6</sup> Dispatch and operational control are the set of actions taken by the TSO in real-time to bring generation units on-line to produce energy. The TSO makes these decisions based upon factors such as unit availability, unit characteristics, and offers to supply, load forecasts and other factors, so as to schedule supply to meet demand. Reliable service must be maintained at all times.

The cost of providing this ancillary service is determined by the embedded costs of operating the grid. The costs are recovered as one component of the transmission tariff. Transmission customers must purchase this service from the transmission provider. The TSO costs are generally allocated and recovered from the customers of the bulk power transmission system based upon their proportional load share. Charges are generally billed monthly.

In the SMD proposed rule, FERC has asked for comment on whether this set of functions should be continued to be treated as an ancillary service, or included as a basic cost of providing transmission service.

### 4. Energy imbalance service

Energy imbalance service is an ancillary service that is required to match discrepancies between actual and scheduled transactions between buyers and sellers in order to maintain load and generation balances. It is often referred to as 'load following' service. The TSO must maintain the proper balance of generation and load within its control area. When the TSO identifies an imbalance in load, it can correct the imbalance by bringing on available generation units. Thus, energy imbalance service can be thought of as the use of generation to correct for *hourly* mismatches between suppliers and their customers. An imbalance can occur when

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<sup>6</sup> To accomplish this, the TSO utilizes tools that recognize reactive limits, unit constraints, unscheduled power flows, transfer limits, self-scheduled resources, bilateral transactions, and generation and reserve requirements.

a market participant has generated or imported more energy than its schedule; generated or imported less energy than its schedule; consumed or exported less energy than its schedule; or consumed or exported more energy than its schedule.

This service must be provided by the TSO when a difference occurs between the scheduled and the actual delivery of energy to a load within a control area over *any single hour*. However, since the TSO owns no generation of its own, it must rely on the resources within the pool to make up any imbalances. This service differs from regulation and frequency response service in that regulation and frequency response service corrects for *instantaneous* variations between generation resources and load, while the imbalance service corrects for variations over the period of *one hour*. A transmission customer may supply energy imbalance through its own load from its own resources or through bilateral agreements; customers that do not have such arrangements must purchase energy imbalance service from their transmission provider.

In effect, energy imbalance service is an accounting mechanism that ensures appropriate compensation for discrepancies between scheduled and actual transactions. In an integrated power grid, the actual amount of energy delivered and taken from any given point on the system is determined after the fact, based on actual metered values. Therefore, the customer's charge for any imbalance is also only known after the fact. Energy imbalance charges are inseparable from energy prices since they reflect the instantaneous cost of acquiring energy. Thus, imbalances are charged at the energy price for that hour in which there was an imbalance.

Under the FERC SMD proposed rule, customers may be required to buy their imbalance service through the day-ahead and real-time energy markets.

## 5. Operating reserves

In an integrated electric system, reserves are necessary to ensure adequate supply during a system emergency. In effect, certain units (or a portion of a unit's capacity) are set aside to respond in such an event. Reserve requirements are necessary to take into account the probability that loads may deviate from forecasts or that unforeseen equipment failure or malfunctions may arise.

Prior to the development of power pools, a utility's reserve requirement was set at the level of its largest generating unit. This resulted in a significant amount of redundant capacity for the system as a whole. With the advent of pooling arrangements, the probability of a system-wide failure is used as the basis for setting the reserve requirement, not an individual utility contingency. This reserve sharing has improved system efficiency greatly.

The level of reserve requirements in the U.S. is set by a separate agency, the North American Reliability Council (NERC). NERC is charged with promoting bulk

electric system reliability and security. Each control area *must* maintain certain reserve requirements designed to provide back-up in the case of the loss of one or more large system-wide contingencies. For example, in New York, the single largest contingency is 1,200 MW and the system-wide reserve requirement is 1,800 MW. Of this reserve requirement, 1,200 MW must be capable of coming on-line within ten minutes.

There are two types of operating reserves that differ only in the time frame with which they can move from reserve status to on-line status in a system emergency.

- Spinning reserves

Spinning reserves are generating units that are on-line (synchronized to the grid) and operating at less than maximum output. The difference between the level at which such a unit is operating, and the level of output it could reach within ten minutes, is known as spinning reserve. Spinning reserves provide fast-response capability as they can provide additional energy to the system rapidly.

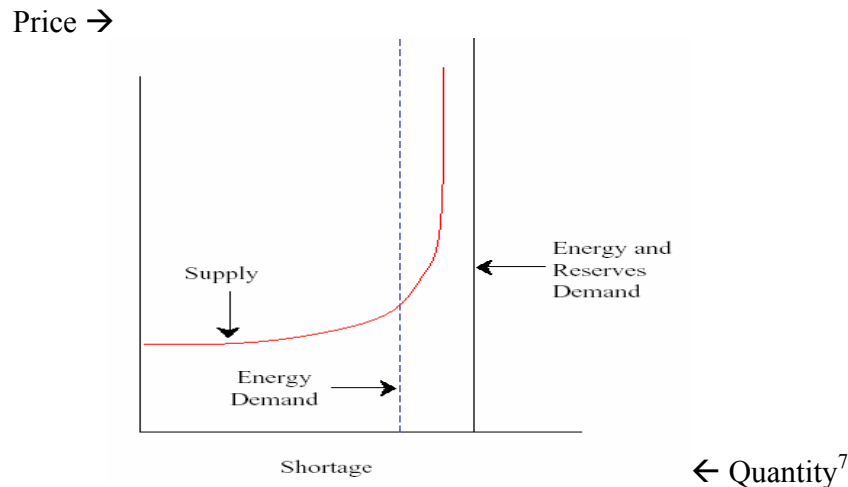
- Supplemental reserves

Supplemental reserves are also able to respond to system emergencies but typically require a longer start-up period, of up to thirty-minutes, to bring on-line. Supplemental operating reserves can include (1) generating units that are operating but unloaded (not yet synchronized to the grid), (2) quick-start units, and (3) curtailable load.

The provision of reserves does not depend solely upon price. NERC criteria must be met even if reserve prices reach extraordinarily high levels. NERC rules are deterministic and inviolate. Each supplier within a control area is responsible for meeting its share of this responsibility. Participants are allocated a proportional share of total system reserves based upon their average load share in relation to the average system peak. Penalties or deficiency charges are imposed upon suppliers that fail to meet reserve requirements.

The demand for reserves is closely tied to the demand for energy for two reasons: (1) at any time, reserve requirements are determined by system load; and (2) energy and reserve products both come from the same generation resource. Generally, a generator will choose to sell that product, energy, reserves, or another ancillary service, that has the greatest value.

The concept of scarcity, brought on by a capacity shortage, is critical to the understanding of reserve markets. In a situation of capacity shortage on the system, when no additional capacity can be made available to meet system needs, a TSO must take whatever capacity is available to meet the NERC reserve requirement, *at any price*. As can be seen from the graph below, in periods of high demand, when the demand curve for reserves is vertical or inelastic, prices will soar to extreme levels. For this reason, all markets in the U.S. have imposed bid caps in the reserve markets during periods of capacity deficiency.



One solution to this problem is to build greater flexibility into the demand-side of the market. One opportunity to provide demand-side response has been termed “curtailable” or “dispatchable” load -- load that can be interrupted or reduced reliably to balance the system as load and supply conditions change. Those market participants who are able to provide curtailable or dispatchable load (typically by entering into contracts with large end-use customers) are paid for providing this service. The availability of these types of demand resources can moderate the price of energy and reserves in times of extreme scarcity.

The market for reserves in the Northeast U.S. is still in the process of being developed. It is now recognized that some ancillary services, such as reserves, can have locational impacts. Therefore, some markets in the U.S. are adding a locational component to enhance ancillary service pricing. For example, locational payments are included in the reserve markets in New York for three sub-areas of the state.

#### 6. Black start service

Black start service is the ability to start up a unit and synchronize it to the system after a major outage without any external source of electricity. The ability to recover from a system-wide failure is essential and not all resources are capable of providing this service. The speed and reliability of the recovery is determined by the number of units that are black start capable. The TSO, which is responsible for reliability, must be able to utilize black start resources upon command. The TSO purchases black start service from generation providers, generally under a long-term contract. The cost of the service is then attributed to all customers on a pro rata basis.

<sup>7</sup> From Scott Harvey, *Lessons from Competitive Ancillary Services Markets*, EUCI Ancillary Services Conference, Denver, Colorado, April 4, 2001.

Black start service is highly dependent upon location. FERC has said that black start service is required for transmission reliability purposes, is a transmission service, and therefore its costs should be borne, as are other transmission-related costs, by transmission customers. Black start charges are cost-based and are charged monthly to transmission customers.<sup>8</sup>

### **C. Pricing of Ancillary Services**

Regulators should encourage the development of uniform licensing and tariff standards for ancillary services to bring greater efficiency to electricity markets and to facilitate interregional trade. Optimally efficient pricing is the goal, based upon the cost of providing the service and the value of the service to the customer.

The pricing of ancillary services can be either cost-based or market-based. There are three essential models for pricing ancillary services: (1) bundle the services with other transmission services into a network tariff; (2) unbundle the services and procure them through contracts or bid solicitation; or (3) unbundle the ancillary services and price them competitively by allowing them to be bid into a day-ahead and/or real-time market for these services. Some ancillary services can also be self-provided by transmission customers that own, or contract bilaterally for, generation.

In Order 888, the FERC required that rates for ancillary services in the U.S. be unbundled from the basic transmission rate. FERC stated:

“Because customers that take similar amounts of transmission service may require different amounts of some ancillary services, bundling these services with basic transmission service would result in some customers having to take and pay for more or less of an ancillary service than they use. For these reasons, the Commission concludes that the six required ancillary services should not be bundled with transmission service.”

FERC did not, at that time, require that such services be sold at market-based rates, but rather allowed rates to be cost-based and established as price caps. FERC approved the rates on a case by case basis. All such rates have to be published and available to all transmission customers.

Under the current SMD proposed rule, FERC is proposing that certain of the ancillary services – regulation, spinning reserves, and supplemental reserves, be provided via a market mechanism.

#### *1. Market-based pricing for ancillary services*

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<sup>8</sup> Such costs can include maintenance, administration, general expenses, depreciation, debt amortization, and training costs as well as the unit’s value in terms of capacity, energy, location, etc.

In a market-based system, all units selected by the TSO for a particular ancillary service will receive the market clearing price (day-ahead or real-time) for each unit of ancillary service provided.<sup>9</sup> Some markets also include a locational component to the market-based rates. The locational component is designed to reflect the scarcity of some ancillary services in congested areas.

In the U.S., where markets for ancillary services are advanced, the TSO will bring generation units on-line in an economic dispatch that cascades the units by the value or price of the service provided. In such a market-based system, where ancillary service requirements are a function of the location of loads and resources across the network, an optimal dispatch should consider energy and ancillary services needs simultaneously. Co-optimization across both the energy and ancillary services markets allows for the incorporation of opportunity cost in the provision of ancillary services so that, at any given time, market participants are indifferent between providing energy or providing ancillary services. In a co-optimized market for energy and ancillary services, generators can bid both energy and each ancillary service into the market at prices that reflect costs.<sup>10</sup> The TSO then schedules generators to meet load requirements. This co-optimization for energy and ancillary services ensures that resources are dispatched at least-cost.

It is important to remember that the cost of supplying reserves, and some other ancillary services, is the opportunity cost of not providing energy. A generator that is providing, for example, reserves is foregoing the energy price that it could receive for all of its output, since reserves are defined as a level of output of a unit below its actual full operating level. The recovery of lost opportunity costs is often allowed. This is the case in New York for providers of ten-minute spinning reserve. All 10 minute reserve generators dispatched by the TSO to maintain reserve below their ideal dispatch point will receive lost opportunity payments based upon the unit's actual lost opportunity cost (based upon a security-constrained dispatch) times the number of megawatts withheld from dispatch for reserve.

### *1. Cost-based pricing for ancillary services*

Where a market for ancillary services is absent or not yet fully developed, pricing of ancillary services should be cost-based. The costs of delivering electrical energy include many components. Pricing of ancillary services can be derived from that set of cost components that is relevant to each ancillary service, such as the cost of providing regulation, the cost of reactive power support, the cost of providing black start capability, the cost of providing spinning reserves, etc. Payments can include a lost opportunity cost (or what the unit would have earned on the energy market if it were eligible for energy dispatch but was designated by the TSO for an ancillary service).

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<sup>9</sup> In some markets, suppliers are paid an incentive-based availability payment based on a Performance Index (or formula) where better performance results in a greater availability payment. This is the case for regulation service and some reserve markets in New York.

<sup>10</sup> There are other technical aspects of generation such as ramp rates and minimum run times that are an integral part of generator's operating characteristics and thus their bids.

Cost-based tariffs are usually based on embedded costs and may include capital costs, operating and maintenance costs, and other relevant costs. In some areas, tariffs are based on contract prices received through a competitive solicitation process. Where possible, a tariff for ancillary services should be based upon the incremental costs of providing the service. Incremental cost pricing leads to the most efficient price for these services. The estimation of these incremental costs is therefore crucial to successful tariff structure. Modeling may be used to simultaneously determine the incremental costs for energy, reserves, and other ancillary services.

Short-run incremental costs of ancillary services can have multiple components. For example the cost of providing reserves often will include the opportunity costs of off-economic dispatch. Similarly, reserve units also have unit start-up and shutdown costs. For regulation service, incremental costs may include the costs of maintenance and reduction in the life-time of the units associated with the impact of continually changing output levels.

Long-run incremental costs can include the cost of any equipment that has the primary purpose of enhancing a unit's ability to increase its output. Such costs can include capital and labor costs, and any operation and maintenance costs to provide such services. For some services such as regulation, this may include the incremental cost of communication facilities that are used to implement regulation.

However, cost-based pricing is difficult to achieve in practice. Using sophisticated modeling, one study found that:

“The embedded-cost prices used by most utilities in their Order 888 tariffs bear little relationship to the costs and prices that would actually occur in competitive markets. Specifically, the capital costs that figure so prominently in the tariff prices are largely irrelevant in short-term competitive markets. And opportunity costs, ignored in cost-of-service analysis, dominate the prices of some ancillary services at some times.”<sup>11</sup>

Identifying these costs may be difficult and regulators must familiarize themselves with the published literature on the costs of such services or refer to studies of particular generating units. Adequate, consistent accounting rules are necessary to ensure appropriate cost-based pricing. Access to financial/cost data, market data, and technical information must be available to the regulators so that they can correctly set cost-based prices.

Whether ancillary services are market-based or cost-based, penalties must be imposed for failure to perform. For example, in N.Y. if a generation unit is called upon to provide voltage support services and fails to do so, it will be assessed a penalty (1/12 of its annual embedded cost). Three such failures will make that unit ineligible to receive any voltage support payments.

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<sup>11</sup> <http://www.ehirst.com/c448.html>

## **D. Charges/Billing for Ancillary Services:**

Charges for ancillary services should be billed to those who cause the system to require these resources. Typically they are charged to those withdrawing energy from the system, i.e., transmission customers such as load serving entities or in some cases exporters or those wheeling energy through an area. Often, the costs of ancillary services are allocated among customers according to their relative loads or load share ratio. These costs may be differentiated by time-of-use to the extent that it is possible to determine how costs vary over time or special pricing can be targeted to customers with rapidly varying loads that burden power systems with regulation or voltage control costs.

Analysts have recently criticized the charges that U.S. customers pay for ancillary services based upon average load. One recent study found that such pricing was inequitable. An analysis of one control area in the U.S. for regulation service showed that “a few large industrial customers account for 34% of system load, compared with 93% of the regulation and 58% of the load-following requirements.” The report concluded that prices should be designed to more closely follow consumption.<sup>12</sup>

## **E. Pricing of ancillary services in the EC and in ERRA (EU Accession) Countries**

Development of ancillary services in the past decade within Scandinavia and partly in continental Europe has been and is today mainly the responsibility of TSO's. However, the application of the services that the TSO's execute in close relation with other market parties is under prescribed rules and procedures.

The involvement of regulatory institutions in these activities in the EU so far has been very limited. There could be several reasons. First – the ex-post regulatory regime, which is present in early liberalized markets (Scandinavia), second – the specific nature of services, and third – the knowledge, skill, software and the need for interconnected data systems (virtual market place) to understand these processes.

The adoption of an amendment to the new EU electricity directive in the summer of 2003 requires strengthening of regulatory involvement and introduction of an ex-ante regulatory regime. In some ways it could change the patterns related to ancillary services in emerging markets.

Today the main coordinated activities within the EU, at the level of TSO's, are taking place under the framework of the Florence process in a forum of transmission system operators (ETSO)

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<sup>12</sup> Hirst, Eric and Kirby, Brendan, *Pricing Ancillary Services so Customers Pay for What They Use*, ORNL, 2000.

In 1999, ETSO was created as an association with ATSOI, UKTSOA, NORDEL and UCTE as founding association members. However, on 29 June 2001, ETSO became an International Association with direct membership of 32 independent TSO companies from the 15 countries of the European Union plus Norway and Switzerland. At the end of 2001 ETSO membership was enlarged to Slovenia and CENTREL countries as full and associate members respectively. In June 2003 the Czech Republic has been admitted as full member of ETSO.

Within ETSO, several working groups have been established to coordinate the common efforts of TSO's in different aspects of their activities. The Balance Management Task Force is in charge of ancillary services. It is worth mentioning that it is the first effort towards harmonization of ancillary services in the EU.

**An important aspect in the context of this issue paper is that in the EU use of term - “ancillary services” is not widespread. Instead, TSO's use the term “balance management/services” to describe those TSO activities associated with power system operation that ensure quality and short-term security of supply.**

**In this chapter of the issue paper, the term “balance/balancing services” is used as meaning a part of “ancillary services” as presently understood in the USA.**

There are also some fundamental differences related to ancillary services across Europe which need to be appreciated before analyzing these services in detail. Also, there are different regulatory regimes in place, which can affect the types of services available. There are several aspects which influence the organization of balancing services.

- The background of exploring the possibility of sharing balancing services and the type of interconnection (A.C. or D.C.) between two systems has a fundamental effect on services that may be available for transfer. Systems which are not operating in synchronism are generally limited to block energy transfers across the D.C. interconnection and are not able to deliver Primary or Secondary control, reactive power, synchronized time correction (via target frequency setting) etc. Although D.C. connections cannot provide synchronicity they may be able to provide some frequency support - but only for one of the two interconnected systems at any one time.
- The size and characteristics of the electricity systems are different, with some systems being large (with high values of inertia), and others much smaller. This may affect the amount of reserve and frequency response held by the TSO, because of the behavior of the system to an event. Also the degree to which systems are interconnected varies, with some systems in central Europe being highly interconnected, and others (generally on the geographic extremities) having only one or two interconnections.
- Members of UCTE have the service of "Secondary Control" which is the automatic simultaneous central control of many generators' control equipment (also known as automatic generation control or AGC). Other systems do not have this capability, which affects the approach to balancing and the types of balancing

services that are required. The type of generating plant connected to a TSO system varies. For example the Nordic systems have a large proportion of flexible Hydro plants, whereas England and Wales have little Hydro generation. This is also true of wind /renewable generation. The balancing services currently available to TSO's are dictated by the type and capabilities of the various plants connected to their respective systems.<sup>13</sup>

In collating details of the variety of services available to different TSO's around Europe, it has become obvious that whilst there is some variation in the types of services utilized, there is a substantial variation in the terminology used. A classic example of this is the term "Secondary" in relation to frequency control. In UCTE, Secondary Control means the central automatic control of a number of generator's control devices. In other areas, this type of central control does not exist and therefore, Secondary has a different meaning. For example in Great Britain, Secondary Response is a subset of Primary Control using the UCTE definitions, while Nordel uses Secondary to refer to manually instructed reserves (which is called 'Tertiary Control' by UCTE).

This highlights the importance of agreeing upon standard terminology that can be used when describing the many types of services available. Most services are tightly defined within the different legal and contractual regimes, making a "like for like" comparison difficult. However it has been found that the purpose behind the varying services is generally common, and so this approach was taken in trying to define the services, given that the technical details of services and the terminology used may be different. Initially, services were grouped into 3 types:

- Frequency Control (automatically delivery)
- Reserves and Energy Balancing (manually instructed delivery)
- Other services (e.g. Reactive power, resolving congestion)

From country to country there are different approaches described by national legal acts setting requirements on the security of supply and also somehow defining the scope and role of ancillary services. In fact, all of the TSO's from Europe (15) and also majority of the TSO's of new member states are cooperating in regional organizations or entities. Four regional organizations and one company have emerged from this co-operation:

- TSOI, the association of TSOs in Ireland;
- UKTSOA, the United Kingdom TSO association;
- NORDEL, the Nordic TSOs;
- UCTE, the Union for the Coordination of Transmission of Electricity, an association of CENTREL, and the TSOs of the Continental countries of Western and Central Europe; and

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<sup>13</sup> In some cases, a significant proportion of CHP is connected. This 'thermal storage' capability can help Balance Responsible Parties to match their generation and load, but is not available to the TSO.

- DC Baltia, a joint venture of energy companies from the Baltic States for coordination of TSO activities within the Baltic's and partly with West Russia and Byelorussia.

The geographic perimeters of these organizations roughly coincide with the boundaries of synchronously interconnected areas. The application and scope of ancillary services differs among countries and also among regional organizations.

Ancillary services can be distinguished according to several parameters: service providers, notice to deliver, time to 100% delivery, is it mandatory or commercial, procurement mechanisms, payment mechanisms, and others.

Countries use different approaches to organizing ancillary services (balancing service) and in Appendix D there are examples of cases from Poland, Slovenia and Finland.

Furthermore to illustrate one way how balancing could be organized, Appendix C includes the terminology and understandings used in the UCTE.

More detailed information regarding balance management (ancillary services) is available at the web sites of UCTE, Nordel, and ETSO:

## **Part II:**

### **A. Introduction**

The purpose of Part II is to provide more detail on the costs and pricing treatment for the ancillary services described above. The rationale for unbundling ancillary services from other energy services was explained in Part I. Regardless of the extent to which markets have achieved liberalization, the electricity sector will be more efficient where market participants understand the costs of ancillary services. So the unbundling of ancillary services will allow transmission customers to better understand the costs of ancillary service and target their business plan accordingly (through self-supply, bilateral contracting, or through purchase from the TSO/IMO).

With unbundling, generation owners will also better understand their own costs of providing ancillary services. Thus they will be able to determine the bid prices at which they are willing to offer these services and they will be better able to choose whether to offer their output for energy or for an ancillary service. And with unbundling, integrated utilities or load serving entities will know the costs of ancillary services so that they can develop appropriate prices to end-use customers who can then use these price signals to operate more efficiently.

In Part II, we will assume that a given country has decided to unbundle ancillary services from other components of the transmission or energy tariff. That is to say that the price for each of the six ancillary services identified in Part I is broken out separately from either the transmission tariff or the all-in energy price. Part II will examine how these separate ancillary services should be procured, how they should be priced, who should pay for them, and who should receive payment for the services.

### **B. Level of Responsibility for Ancillary Services**

As described in Part I, ultimately the TSO or IMO is responsible for the provision of ancillary services since they are charged with system safety and reliability. However, since the TSO or IMO in most cases no longer owns generation, or is functionally separated from its generation affiliates, then it must acquire those services from generation sources within the network. Since ancillary services are critical to the safe and reliable operation of the network it is the *users* of the network, i.e., the transmission customers such as load serving entities, that are responsible for paying for these services.

### **C. Allocation of Ancillary Services Costs among Customers**

Historically, the cost allocation methodology for ancillary services, to load serving entities or transmission customers, is based on load usage. The markets for ancillary services are

somewhat more sophisticated in that the customer purchases only what they need from the TSO or IMO at prices determined in a transparent auction. The transmission customers or load serving entities then pass these costs along to their end-use customers and in some instances may charge them directly for their share of these ancillary services based upon the end-use customer's demand characteristics such as peak load, time of day, or power factor. End-use pricing based upon load characteristics will provide the proper incentives to the end-use customers to take actions that would reduce the demand on the system for these ancillary services.

## **D. The Settlement Process**

It is generally the TSO or IMO that acts as the settlement agent between the users of ancillary services and the suppliers of ancillary services. Where markets for ancillary services have been developed it is usually the market operator or IMO that acts as the settlement agent. It bills transmission customers for their use of ancillary services on a monthly basis. The generation suppliers who provide the ancillary services are in turn compensated by the TSO or IMO from the revenue it collects from transmission customers. For market-based services, the ancillary service providers are paid the market clearing price for that service times the amount of service provided. For cost-based ancillary services the suppliers are allowed to recover their costs of providing each of the ancillary services including, in some cases, lost opportunity cost.

## **E. Options for the Procurement of Ancillary Services**

While there is a trend toward market-based procurement for some ancillary services, cost-based tariffs are still used to price some ancillary services. The question of whether ancillary services should be provided under a cost-based regime or a market-based system is not an either/or question. Even in areas that are implementing sophisticated market-based systems for electricity, such as the Northeast U.S., cost-based procurement of ancillary services co-exists with market-based mechanisms. Some ancillary services such as voltage support, black start, and system services are procured on a non-market basis, i.e., they are procured via a cost-based tariff rather than being procured via an auction. By contrast, regulation/frequency response, reserves, and energy imbalances are procured via market-based auctions.

Market-based pricing is utilized for ancillary services in areas of the U.S. that have sophisticated wholesale markets. However, even where bid-based markets for ancillary services exist, the transmission customer is still allowed to self-supply or provide for third-party or bilateral supply of ancillary services. It is only if the user does not self-supply in some way that the system operator becomes the ancillary service provider of last resort.

The Northeast energy markets are built around bid-based auctions in an integrated wholesale market system. Some states, such as New York, have co-optimized the energy and ancillary services markets. Under co-optimization, the energy and ancillary services

products are optimized simultaneously subject to relevant network constraints. A proper optimization algorithm for settling the auctions, done using sophisticated computer software, should result in ancillary service marginal prices that are the incremental cost for meeting an additional MW of the required ancillary service.<sup>14</sup>

The following sections discuss some of the details of setting prices for ancillary services. These details are based upon the system currently in place in New England.

## **F. Setting of Cost-Based Prices**

### ***A. Reactive supply/voltage control (voltage support)***

As described in Part I, voltage support is necessary for grid reliability thus it is the ultimate responsibility of the TSO or IMO to ensure proper voltage support at all times. Voltage support is obtained from generators that are capable of providing or absorbing reactive power. In order to ensure reliability, from time to time, the TSO or IMO may direct certain generation facilities to operate to produce or absorb reactive power. The TSO or IMO determines the amount of voltage support needed based upon technical criteria used to maintain system reliability. Transmission customers must purchase this service from the transmission network operator (TSO or IMO). Each transmission customer's energy transaction is assessed a portion of the charges for the provision of voltage support.

The costs for voltage support services are generally based on the embedded costs of the generators providing the service plus any opportunity cost they may incur if they are backed down from providing energy to provide voltage support. In New England, the charges for voltage support service are determined based upon a formula which includes:

- (1) The capacity costs of units providing voltage support
  - The VAR rate is established annually on a prospective basis
  - The base VAR rate is calculated based on estimates of the carrying cost per kVar per year of generating equipment that provides VAR support (e.g.; \$1.00/kVAR-yr in 2003) adjusted by (a) the forecasted peak reference load and (b) the unit's seasonal claimed capability rating;
- (2) The net energy costs of units providing voltage support
  - Energy-producing units used to provide voltage support are those units brought on-line out of merit order for such support
  - They are paid energy-related charges for the hours that they are used to provide voltage support – both for energy produced and energy consumed (such as to power pumps); and

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<sup>14</sup> The mathematical proof of this can be found in the paper, "Pricing Energy and Ancillary Services In Integrated Market Systems by an Optimal Power Flow," by Ziad Alaywan, Tong Wu, and Mark Rothleder.

- (3) The lost opportunity costs for units providing voltage support
  - Based upon the difference between the unit's output for voltage support and the expected output of the unit if it were dispatched in economic merit order for energy
  - This output amount is then multiplied times the energy clearing price in that hour during which the unit was used for voltage support.

The total monthly VAR payment to generators is 1/12 of the annual VAR rate times the qualified VARS used to provide voltage support.

The sum of the voltage support costs determined in the manner described above are apportioned to transmission customers based on their load ratio share of all transactions for that hour. Payment for voltage support services is collected from transmission customers. These payments are then given to the generators who are providers of voltage support services.

Generally, end-use customers in the U.S. do not pay directly for voltage support unless they are direct customers who take service under a transmission, rather than distribution, tariff. In some areas, large customers take service directly under a transmission tariff and they would be assessed these charges based upon their load requirements.

#### ***B. Scheduling, System Operation Control and Dispatch (system services)***

These are system services which can only be provided by the TSO/IMO. These services are necessary for movement of power within, or into or out of, the network system. This service also includes dispatch and security analysis services. All users of the system require these services therefore they are charged to all users usually via a separate component of the transmission tariff.

The price for these services is determined by the TSO or IMO (whomever is providing the services) based upon its administrative and operations expenses. These expenses are determined annually based on the previous year's cost data and recalculated on an annual basis.

Each transmission customer is obligated to pay this charge on a monthly basis based the number of kilowatts of its monthly load.

#### ***C. Black start or system restoration services***

As described in Part I, system restoration services are required in the event of a blackout to get the system back up and running quickly. This responsibility belongs to the TSO or IMO which must procure these services from certain generators that can re-energize or start up without the need for an external power source. Due to the nature of the grid, there are locational aspects to system restoration services.

Therefore the grid operator must have the ultimate responsibility for system restoration in the event of a blackout. The TSO or IMO pre-certifies certain generating units as capable of providing system restoration services and those units provide this service to the TSO or IMO under written agreement. In New England these agreements must be for a minimum of three years.

Load serving entities must purchase system restoration services from the TSO or IMO and they are charged a cost-based price (based upon the costs of all units providing the service) multiplied times their load share. This charge is a separate charge on the transmission customer's bill.

The cost of the service is determined based upon the operation and management costs of the generators which have been certified as black start units. This is usually a pre-determined monthly base rate provided per kW-year (\$4.00 per kW-year/12 in 2004) and multiplied times the unit's claimed black start capability. The TSO or IMO collects the revenues for system restoration from the load serving entities and then pays those generation units that provided the service.

## **G. Setting of Market-Based Prices**

### ***A. Energy imbalances***

As described in Part I, energy imbalance service is provided by the TSO or IMO when a difference occurs between the scheduled delivery of energy and the actual delivery of energy to a given load. A supplier providing energy may either self-supply all energy (using its own resources or bilateral contracts) or obtain energy sufficient to meet its load obligation from the TSO/IMO from the pooled energy resources available.

In the wholesale electricity markets of the Northeast there is no longer a need to make a separate determination of the amount of energy imbalances since these imbalances are known automatically through the real-time electricity market and they are billed through the internal settlement process. The charge or credit for any energy imbalance is the applicable energy clearing price at the time the imbalance occurred and is billed directly to the transmission customer that has the imbalance.

### ***B. Regulation/frequency response***

As described in Part I, regulation is necessary to balance the supply of energy against minute-to-minute variations in load. In a balanced situation, optimal frequency should be maintained at 60 Hertz. System collapse is likely if the system frequency falls to 57 or rises above 63 Hertz. To the extent that frequency is out of balance, the TSO or IMO has to call on generation resources to provide automatic generation control (up or down) to bring the system back in balance.

In New England, regulation is a market-based product. There is both a day-ahead and a real-time market for regulation. Each market participant with a real-time load obligation has an obligation to provide regulation. Each such customer is assigned an hourly regulation obligation equal to its share of the system-wide requirement for regulation within that hour, based on the customer's real-time load obligation in that hour.

A customer may self-supply regulation (by providing its own resources or by contracting bilaterally from other resources within the system) or it may purchase regulation on the market to meet this obligation. If the customer provides more regulation than its obligation then it is given a credit for this amount based on the regulation clearing price at the time. If a customer does not have enough regulation to satisfy its obligation it is required to purchase the shortfall from the TSO/ISO through the regulation market.

Generators with excess regulation resources may bid this product into the regulation market. Generators are pre-certified to be able to bid into this market and they will bid the amount of regulation that they are willing to provide at a given time at a price that they determine. Only if their bid (including their opportunity costs) clears the regulation market auction (i.e., is the lowest bid in merit order) will the TSO/IMO bring the unit on-line to provide regulation services. Once a generating unit is brought on-line to provide regulation service it is paid the clearing price in the regulation market for the time that it was in service plus its estimated unit-specific opportunity costs. The TSO/IMO determines unit-specific estimated opportunity costs on the basis of the expected energy sales foregone if that unit had been dispatched in economic order for energy.

A net purchaser of regulation is charged for this service at the real-time regulation clearing price based on its real-time load obligation. It is also charged a share of the lost opportunity cost credits paid to the generators providing regulation service in that hour.

All of the credits and charges, to both generators and load serving customers, are provided by the TSO/IMO settlements operation and netted against one another in the customer's monthly bill. The regulation schedule for the New England ISO is attached in Appendix A.

### ***C. Operating reserves***

Part I provides a summary of characteristics of well-functioning markets for reserves. At present, all markets in the Northeast U.S. are in the midst of reform of their reserve markets. Thus there is no one model for a reserve market whose design is both well accepted and tested. This discussion of reserves will be limited to the most recent evolution in the reserve markets – the plan of New England to implement a forward market

for reserves. This new market design was approved by the FERC in November of 2003 and implemented soon after.

The new market design for reserves in New England is not a true co-optimized market for energy and reserves. New York does have such a co-optimized reserve market. As noted in Part I, co-optimization of energy and reserve markets will result in the most efficient allocation of resources in both markets, in both real-time and in day-ahead procurement. Co-optimization should also provide efficient prices to operating reserves which reflects the optimal allocation of those resources. New England is scheduled to implement co-optimization of the energy and reserve markets in 2005.

Operating reserves can be thought of as the system's insurance policy. These ancillary services provide a margin of safety to ensure that the grid will operate reliably under even the most severe circumstances. The availability of Operating Reserves is relied upon and utilized by the system operator anytime there is an unplanned contingency on the system. By deploying these reserves of stand-by energy the TSO/IMO can keep the grid operating at full capacity even after the loss of a large unit somewhere in the system. In New England, the Operating Reserve levels are set so that the system operator can maintain reliability even with the loss of its two largest sources of power at the same time.

New England has two separate products for reserves, Spinning Reserves and Supplemental Reserves. But these products are not true separable markets; rather they are both derivatives of the energy market. Generators providing Operating Reserves are compensated by the ISO in the form of a credit. The credit includes their submitted bids in the energy market plus their start-up and no-load costs. This ensures that generators who provide reserves can recover all the costs associated with providing Operating Reserve service instead of pure energy service.

However, this method of compensating Operating Reserves still has some flaws. Off-line reserves do not receive any revenues from providing operating reserves and only receive energy payments when called upon to produce. Many have identified this lack of incentive, for off-line units to provide reserves, as a major flaw in the Operating Reserve market. The new forward reserve market is designed to overcome this flaw.

The new Forward Reserve market in New England is a separate market. In this market, reserve resources are procured by use of a "call option" on energy. Prices for Forward Reserves are determined through a competitive auction. The auction is based upon a call option that is in essence a reservation payment to be made to selected generation units that have been chosen in the auction to act as reserves. This is a forward market because auctions are held 1 to 6 months prior to the need for the service. Past experience has shown that spot markets for reserves without forward markets result in significant volatility since in real-time the supply curve for reserves is vertical. A forward market will allow reserve suppliers to respond to longer term price expectations, thus removing significant volatility from the market.

In the Forward Reserve auction, units must specify whether they are providing off-line or on-line reserves. Bids for on-line units will be able to recover their start-up and no-load costs so that their total costs are included in the bid. Those units chosen in the auction will be required to bid into the energy market at, or above, a pre-determined “Strike Price.” In this case, the Strike Price is a minimum energy offer price and it is designed to be a self-selection mechanism for generators. The Strike Price is defined as a heat rate (currently set at 15,000 mmBTU/kWh) multiplied times a fuel index.

This heat rate and Strike Price were developed so as to be consistent with the operating profile of a gas-fired peaking unit (the marginal unit in New England), thus ensuring that the reserves will be dispatched for energy infrequently (since they will in fact be “on reserve”) but also set high enough to encourage investment in plant upgrades. The units selected in the auction, the Forward Reserve Resources, are chosen in merit order based upon their bids above the Strike Price.

Forward Reserve Resources will be expected to provide energy as either (1) 10 Minute Forward Reserves, or (2) 30 Minute Forward Reserves. Once a Forward Reserve Resource has been dispatched to provide energy it will be eligible to set the energy clearing price in the real-time market. Forward Reserve Resources that fail to meet the energy deliverability requirement will not be paid any compensation and could be subject to a penalty for either failure to activate or failure to provide capacity when called.

This Forward Reserve market interacts with the spot market for energy in the following way. If a system contingency occurs, then the TSO/IMO will dispatch all units that have the cheapest energy first, even if they are not Forward Reserve units. Since any given unit can produce energy or reserves, the choice of whether to bid into the Forward Reserve market or stay completely available to produce energy will depend upon the unit-specific opportunity cost of foregoing energy production.

Here are the results of the first Forward Reserve Auction in New England held on December 8, 2003:

*Table 1:*

10 Minute Forward Reserve			30 Minute Forward Reserve		
Total Supply Offers (MW)	Cleared (MW)	Clearing Price (\$MW-Month)	Total Supply Offers (MW)	Cleared (MW)	Clearing Price (\$MW-Month)
1908.039	1623.896	4495.00	1565.5	252.0	4495.00

It is clear from these results that a forward market for reserves can work. The New England ISO considers these results to be within a reasonable range.<sup>15</sup> In addition, the clearing price should be adequate to induce some plants to finance improvements over time.

<sup>15</sup> [http://www.iso-ne.com/FERC/filings/Other\\_ISO/Compliance\\_Report\\_FRM\\_01\\_13\\_04.pdf](http://www.iso-ne.com/FERC/filings/Other_ISO/Compliance_Report_FRM_01_13_04.pdf) at page 6.

The next step in the development of the New England market is to incorporate a demand curve for reserves. This proposed methodology for reserves is designed to further overcome the vertical supply and demand curves that exist during system peak usage. The demand curve methodology will also improve the reserve markets because it will have a locational component. New York is working on a similar demand curve methodology to improve its reserve markets.

## H. Conclusion:

Key issues to consider in the region when developing tariffs for ancillary services include:

### 1. Terminology

- Be aware of the differences in terminology used by national TSOs.
- Encourage countries within the region to use common definitions for ancillary services. A common understanding of ancillary services terminology among TSOs and regulators will facilitate regional discussions.

### 2. Eliminate seams

- Consider the development of common standards and metrics for the supply, delivery, and consumption of ancillary services. Common standards will both facilitate trade within the region and assist in the development of regional markets for both energy and ancillary services.
- Encourage participation of national TSOs in professional associations. This will encourage a common understanding of ancillary service policies in the region.

### 3. Set prices based on costs where markets do not exist

- Not all ancillary services are amenable to market-based procurement. For those services (such as voltage support and black start) prices should be based on embedded costs.
- Investigate methodologies for the pricing of ancillary services. Gather information about how to measure the cost of these services.
- Require adequate cost details from providers and apply consistent accounting rules. This will aid in designing tariffs that are accurate and cost-based.

### 4. Establish competitive markets for ancillary services, where feasible

- A competitive market for ancillary services requires a competitive market for energy.
- A competitive market for key ancillary services (those amenable to markets) will allow both suppliers and consumers to enter into mutually satisfactory transactions, thus achieving the most efficient price possible.

### 5. At a minimum, unbundle ancillary services:

- Since energy and many ancillary services are substitutes for one another, the pricing of capacity-based ancillary services, such as regulation/frequency response, and spinning and supplemental reserves, should be unbundled from the other embedded costs of the transmission system that are included in transmission rates, especially where there has been functional separation of ownership from operation.

- Consider procuring other ancillary services, such as regulation and black start capability, through long-term contracts between generation providers and the TSO.

Allow transmission customers to self-supply some ancillary services either through provision of their own units or through bilateral arrangements with other suppliers.

## Appendix A

### Examples from the U.S.

Three U.S. Northeast markets (Pennsylvania/New Jersey/Maryland (PJM), New England (NE), and New York (NY) have ancillary service markets that share many of the characteristics described above, but there are many differences as well. In addition, some ancillary service markets, particularly reserve markets, are still in the process of being redesigned. Because of these differences, it is not easy to compare prices across the region. Below are some examples of ancillary service prices from some of these markets.

#### 1. New York Ancillary Services

New York offers the following ancillary services. The prices shown are average prices for January – July, 2002.<sup>16</sup> Operating reserves include three sub-markets for 10 minute spinning reserve, 10 minute non-synchronous reserve, and 30 minute reserve.

Table 2:

Ancillary Service	Current average cost
Regulation	<b>\$0.02 per MWH</b>
Voltage Support	<b>\$0.34 per MWH</b>
Scheduling, System Control & Dispatch	<b>\$1.95 per MWH</b>
Energy Imbalance	<b>Market price</b>
Operating Reserve	<b>\$0.23 per MWH</b>
10-minute spinning reserve	<b>East: \$2.17 per MWh West: \$1.98 per MWh</b>
10 minute non-spinning reserve	<b>East: \$1.56 per MWh West: \$1.35 per MWh</b>
30 minute reserve	<b>\$1.15 per MWh</b>
<b>Black Start</b>	<b>\$0.001 per MWH</b>

#### 2. New England Ancillary Services

The New England system operator offers the following ancillary services:

1. Scheduling, system control and dispatch
2. Reactive supply and voltage control
3. Regulation and frequency response service
4. Energy imbalance service

<sup>16</sup> ISO New York Market Orientation Course, *Introduction to Ancillary Services*, Jack Valentine, 2002.

5. Operating reserves – Spinning
6. Operating reserves – Supplemental
7. System restoration and planning (black start).

Of those, four ancillary services are traded in the ISO-NE markets. They are Automatic Generation Control (AGC), Ten-Minute Spinning Reserve (TMSR), Ten Minute Non-Spinning Reserve (TMNSR), and Thirty-Minute Operating Reserve (TMOR).

The prices shown are the range of prices in Quarter 4, 2001.<sup>17</sup>

Table 3:

Ancillary Service	Average Q4 2001
Regulation	<b>\$ 5.08 – \$ 5.91 per reg-hour<sup>18</sup></b>
TMSR	<b>\$ 0.49 – \$1.36 per MW</b>
TMNSR	<b>\$ 0.46 – \$ 0.54 per MW</b>
<b>TMOR</b>	<b>\$ 0.11 – 0.17 per MW</b>

### 3. PJM Ancillary Services

PJM is responsible for directing the supply, and coordinating the provision, of ancillary services. PJM is required to provide, and transmission customers serving load within the Control Area are required to purchase, the following services:

1. Scheduling System Control & Dispatch
2. Reactive Supply & Voltage Control from Generation Resources
3. Regulation & Frequency Response
4. Energy Imbalance Service
5. Operating Reserve Service including (1) day-ahead operating reserves, (2) balancing operating reserves, and (3) spinning reserves.

Of those, four ancillary services are traded in the PJM markets. They are (1) regulation, (2) day-ahead operating reserves, (3) balancing operating reserves, and (4) spinning reserves. Here are the service rates for these services for the fourth quarter of 2001.<sup>19</sup>

Table 4:

Ancillary Service	Q4 2001 Service Rate
Regulation	<b>\$0.33 per MWh</b>
Day-ahead operating reserve	<b>\$0.15 per MWh</b>
Balancing operating reserve	<b>\$0.76 per MWh</b>

<sup>17</sup> ISO New England, Market Report for Quarter 4 FY 2001 (February 2002-April 2002).

<sup>18</sup> A reg is equivalent to approximately 0.42 megawatts. Prices in regs cannot be strictly compared to the prices of other services that are in \$/MW.

<sup>19</sup> <http://www.caiso.com/docs/2002/11/18/200211181001074925.pdf>

<b>Spinning reserve</b>	<b>\$0.12 per MWh</b>
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#### 4. Non-market based tariff

Below is an example of an ancillary services tariff schedule from The American Transmission Systems, Inc. (ATSI). ATSI is the Control Area Operator and Transmission Provider for the FirstEnergy Corp. operating companies of The Cleveland Electric Illuminating Company and the Ohio Edison Company.

ATSI ancillary service schedule as of October 14, 2002

Table 5:

Price s are as poste d in the ATSI tariff. *Daily On- Peak is Week day s -	<b>BULK TRANSMISSION PRICING</b>						
		<b>Schedule-1</b>	<b>Schedule-2</b>	<b>Schedule-3</b>	<b>Schedule-4</b>	<b>Schedule-5</b>	<b>Schedule-6</b>
	<b>TYPE</b>	<b>Scheduling, Dispatch, and Control</b>	<b>Reactive Supply</b>	<b>Regulation &amp; Frequency Control</b>	<b>Energy Imbalance</b>	<b>Spinning Reserves</b>	<b>Supplement Reserves</b>
	<b>Yearly</b>	\$672.00	\$1,211.88	\$778.80	D band=1.5%	\$1,168.20	\$585.00
	<b>Monthly</b>	\$56.00	\$100.99	\$64.90	- =Sys E Cost	\$97.35	\$48.75
	<b>Weekly</b>	\$12.92	\$23.31	\$15.00	+ = \$100/MWh	\$22.50	\$11.25
	<b>*Daily- on</b>	\$1.85	\$4.66	\$3.00	see	\$4.50	\$2.25
	<b>Off</b>	\$1.85	\$3.33	\$2.14	complete	\$3.21	\$1.605
	<b>**Hourly-on</b>	\$0.08	\$0.29	\$0.187	tariff	\$0.281	\$0.141
	<b>Off</b>	\$0.08	\$0.14	\$0.089		\$0.134	\$0.067

Monday through Friday  
NERC specified holidays  
Days  
Sunday and NERC specified holidays

\*Daily Off-Peak is Saturday, Sunday and  
\*\*Hourly On-Peak is HE 0800 - HE 2300 Week  
\*\*Hourly Off-Peak is all other weekday hours plus Saturday,

## 5. New England Ancillary Services Tariffs

The following are actual current tariff sheets from the New England ISO (as of October 2003) for its ancillary services. These tariff sheets are filed with the FERC as part of the ISO New England Open Access Transmission Tariff (OATT). They describe cost-based services for system services (Schedule 1), reactive supply (Schedule 2), and system restoration or black start (Schedule 16). They also include a brief description of the market-based ancillary services for Regulation (Schedule 3), Energy Imbalance Service (Schedule 4), Operating Reserves –Spinning (Schedule 5), and Operating Reserves Supplemental (Schedule 6). The market-based tariffs refer to Market Rule 1 which is the comprehensive document that sets out all of the rules for the operation of the New England energy, capacity, and ancillary service markets.

### **SCHEDULE 1 SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE**

Scheduling, System Control and Dispatch Service is the service required to schedule at the regional level the movement of power through, out of, within, or into the RTO-NE Control Area. Local level service is provided by the PTOs under Schedule 21 to this OATT. For Transmission service under this OATT, this Ancillary Service can be provided only by RTO-NE and the transmission Customer must purchase this service from RTO-NE. Charges for Scheduling, System Control and Dispatch Service are to be based on the expenses incurred by RTO-NE, and by the individual PTOs in the operation of Local Control Center dispatch centers or otherwise, to provide these services. The expenses incurred by RTO-NE in providing these services recovered under Section IV of the OATT. A surcharge for the expenses incurred by PTOs in the provision of these services for transmission service over the PTF will be added to the Through or Out Service rate and to the Regional Network Service rate. Any Scheduling, System Control and Dispatch Service expenses for the provisions of these services for MTF Service shall be determined separately and assessed to Transmission Customers receiving MTF Service, in accordance with the arrangements between the Transmission Customers receiving MTF Service and the MTF Provider.

The expenses incurred in providing Scheduling, System Control and Dispatch Service for transmission service over the PTF for each PTO will be determined by an annual calculation based on the previous calendar year's data as shown, in the case of PTOs which are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year, and shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report. The surcharge shall be determined annually as of June 1 in each year and shall be in effect for the succeeding twelve (12) months. The rate surcharge per kilowatt for each month is one-twelfth of the amount derived by dividing the total annual PTO expenses for providing the service by the sum of the average of the coincident Monthly Peaks (as defined in Section II.21.2) of all Local Networks for the prior calendar year.

Each Transmission Customer which is obligated to pay the rate for Regional Network Service for a month shall pay the surcharge on the basis of the number of kilowatts of its

Monthly Network Load (as defined in Section II.21.2 of this OATT) for the month. Each Transmission Customer which is obligated to pay the rate for Through or Out Service for the applicable period shall pay the surcharge on the basis of the highest amount of its Reserved Capacity for each transaction scheduled as Through or Out Service for such period. The details for implementation of Schedule 1 for transmission service over the PTF shall be established in accordance with the Implementation Rule for Schedule 1 attached to this OATT.

## **SCHEDULE 2 REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE**

In order to maintain transmission voltages on the RTO-NE Transmission System (for voltage constraints that are reflected in RTO-NE's systems for operating the RTO-NE Transmission System or in RTO-NE's operating procedures) within acceptable limits, generation facilities are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on the RTO-NE Transmission System (for voltage constraints that are reflected in RTO-NE's systems for operating the RTO-NE Transmission System or in RTO-NE's operating procedures). The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to a Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Owners. Additional information regarding the processes used to collect data and calculate amounts due or payable under this Schedule 2 can be found in the Ancillary Service Schedule 2 Business Procedure posted on the RTO-NE website. Local level service may be provided by the PTOs under Schedule 21 of this OATT.

### **I. DETERMINING THE AMOUNT TO BE PAID FOR SERVICE UNDER THIS SCHEDULE**

Reactive Supply and Voltage Control from Generation Sources Service is to be provided through RTO-NE and the Transmission Customer must purchase through RTO-NE service for voltage support capability provided by Qualified Generators and service when RTO-NE (or applicable Local Control Center dispatching center) determines, in the exercise of its discretion, that it is necessary to direct a generating unit to alter its operations in an hour in order to provide such service. The charge for such service shall be paid by each Transmission Customer which receives either Regional Network Service or Through or Out Service and shall be determined in accordance with the following formula:

$$CH = (CC + LOC + SCL + PC) \frac{HL_1 + RC_1}{HL_1 + RC}$$

in which

CH = the amount to be paid by the Transmission Customer for the hour;

- CC = the capacity costs for the hour shall be the VAR Revenue Requirement determined as set forth herein divided by the number of hours in the month;
- LOC = the lost opportunity costs for the hour to be paid to Market Participants who provide VAR support;
- PC = the portion of the amount paid to Market Participants for the hour for Energy produced by a generating unit that is considered under this Schedule 2 to be paid for VAR support;
- SCL = the cost of energy used in the hour by generating facilities, synchronous condensers or static controlled VAR regulators in order to provide VAR support to the transmission system;
- $HL_1$  = the Regional Network Load of the Transmission Customer for the hour;
- HL = the aggregate of the Regional Network Loads of all Transmission Customer for the hour;
- $RC_1$  = the Reserved Capacity for Through or Out Service of the Transmission Customers for the hour; and
- RC = the aggregate Reserved Capacity for Through or Out Service of all Transmission Customers for the hour.

## **II. DETERMINING A GENERATOR'S COMPENSATION FOR PROVIDING SERVICE UNDER THIS SCHEDULE**

The compensation to be paid to generators providing Schedule 2 service shall be based on the four components set forth below.

### **1. Capacity Cost (CC)**

1.1. A Qualified Generator shall be eligible to receive compensation for the capability to deliver VARs to the system (a "VAR Payment") under the Capacity Cost component of Schedule 2 as provided herein. A "Qualified Generator" is any generator that is in the RTO-NE Market System and provides measurable voltage support, as determined from time to time by RTO-NE to the RTO-NE Control Area.

1.2. The VAR Payment is not intended to compensate a Qualified Generator for losses associated with station use and energizing the generator leads and generator step-up transformer.

1.3. The "VAR Rate" will be established each year as of January 1 on a prospective basis for that calendar year and shall be the Base VAR Rate \* Min (1, (1.2\*Forecast Peak Adjusted Reference Load for the year/SUM (Qualified Generator's Seasonal Claimed Capability))).

1.4. The "Base VAR Rate" shall be \$0.90/kVAR-yr in 2001; \$0.95/kVAR-yr in 2002; \$1.00/kVAR-yr in 2003 and \$1.05/kVAR-yr in 2004 and thereafter.

1.5. The “Forecast Peak Adjustment Reference Load” shall be the value published in the then- most recently published CELT report at the time the VAR Rate is established for a year.

1.6. A “Qualified Generator’s Seasonal Claimed Capability” shall be the Seasonal Claimed Capability of each Qualified Generator applicable for the season in which the RTO-NE Forecast Peak Adjusted Load is forecast to occur.

1.7. The “VAR Revenue Requirement” shall be the SUM (Qualified Generator’s VAR Payment).

1.8. A Qualified Generator’s VAR Payment shall equal the  $(1/12) * (\text{VAR Rate} * \text{Qualified VARs})$ .

1.8.1. The VAR Rate is determined pursuant to paragraph 1.3 above.

1.8.2. Qualified Generators will be paid their VAR Rate under this Section for each month of a calendar year starting with the month in which this Section becomes effective.

1.9. “Qualified VARs” shall be:

1.9.1. Qualified VARs of an untested unit shall be equal to the Lagging VAR capability at Seasonal Claimed Capability for the season of forecasted peak as indicated on the Qualified Generator’s NX-12D form that is then in effect adjusted for losses to station service and energizing the generator leads and generator step-up transformer.

1.9.2. As soon as practicable, but in no event longer than two years from the effective date of this Section, the Qualified VARs of a Qualified Generator shall be determined at its point of delivery to the system, in accordance with the then-applicable Operating Procedures. At least every five (5) years after that test, a test of the VAR capability of a Qualified Generator across its full operating range shall be conducted.

## **2. Lost Opportunity Cost (LOC)**

2.1. The Lost Opportunity Cost for hydro, pumped storage and thermal generating units that are dispatched down by RTO-NE, a PTO’s Local Control Center, or PTO dispatch center for the purpose of providing reactive supply and voltage control will be calculated pursuant to Market Rule 1.

## **3. Cost of Energy Consumed (SCL)**

3.1. Motoring Hydro or Pumped Storage Generating Units. The SCL associated with hydro and pumped storage generating units that are motoring at the request of

RTO-NE, a PTO's Local Control Center, or PTO dispatch center for the purpose of providing reactive supply and voltage control will equal the cost of energy to motor and will be calculated in each hour as follows:  $SCL = (MWhUnit * (ECP \text{ or } LMP \text{ or Actual energy cost}))$ , where the MWh Unit are calculated pursuant to the Schedule 2 Business Procedure. Actual energy cost applies only if motoring energy is purchased through a bilateral contract.

3.2. Synchronous Condensers and Static Controlled VAR Regulators (SC/SCV). The SCL will be set to zero (\$0), and the cost of energy to supply reactive supply and voltage control from the Chester SCV will be treated as losses on the RTO-NE Transmission System. This treatment will be revisited by RTO-NE on an as-needed basis (e.g., upon the addition of a new SC or SCV within the RTO-NE Control Area).

#### **4. Cost of Energy Produced (PC)**

4.1. Thermal Generating Units. The PC associated with thermal generating units brought on-line by RTO-NE, a PTO's Local Control Center, or PTO dispatch center for the purpose of providing reactive supply and voltage control shall equal the portion of the total uplift to be paid that resource for a day that is attributed to the hour(s) during which the resource is run to provide this service in accordance with Market Rule 1 and RTO-NE System Rules.

4.2. Hydro and Pumped Storage Generating Units. The PC associated with hydro or pumped storage generating units that are producing real power and that have also been brought on-line by RTO-NE, a PTO's Local Control Center, or PTO dispatch center to provide reactive supply and voltage control shall equal the portion of the total uplift to be paid that resource for a day that is attributed to the hour(s) during which the resource is run to provide this service in accordance with Market Rule 1 and RTO-NE System Rules.

### **SCHEDULE 3**

#### **REGULATION AND FREQUENCY RESPONSE SERVICE (AUTOMATIC GENERATION CONTROL)**

Regulation and Frequency Response Service (Automatic Generator Control) is necessary to provide for continuous balancing of resources (generation and interchange) with Load, and for maintaining scheduled interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service (Automatic Generation Control) is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with RTO-NE and this service will be available to all Transmission Customers that have a load obligation in the RTO-NE Market pursuant to Market Rule 1. The Transmission Customer must either take this service from RTO-NE

through the RTO-NE Market or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service (Automatic Generator Control or AGC) obligation.

Charges for this Service shall be determined on the basis of offers submitted by Market Participants in accordance with Market Rule 1. The transmission service required with respect to Regulation and Frequency Response Service (Automatic Generator Control) will be paid for as part of Regional Network Service or Through or Out Service by all Market Participants and other entities that have a load obligation in the RTO-NE Market Pursuant to Market Rule 1. The charge for Regional Network Service is determined in accordance with Schedule 9 to this OATT.

#### **SCHEDULE 4 ENERGY IMBALANCE SERVICE**

Energy Imbalance Service is the service provided when a difference occurs between the scheduled and the actual delivery of energy to a load obligation in the RTO-NE Market in accordance with Market Rule 1 during a single hour. The Transmission Customer may either supply its load obligation from its own resources or through bilateral transactions or obtain the service through the RTO-NE Market. This service will be available to all Transmission Customers or Market Participants that have a load or generation obligation in the RTO-NE Market pursuant to Market Rule 1. The prices for such service will be the applicable Locational Marginal Prices determined pursuant to Market Rule 1.

The transmission service required with respect to Energy Imbalance Service will be furnished as part of Regional Network Service or Through or Out Service to all Transmission Customers that have a load or generation obligation in the RTO-NE Market in accordance with Market Rule 1. The charge for Regional Network Service is determined in accordance with Schedule 9 to this OATT. The charge for Through or Out Service is determined in accordance with Schedule 8 to this OATT.

#### **SCHEDULE 5 OPERATING RESERVE - SPINNING RESERVE SERVICE**

Spinning Reserve Service is a service needed to serve load immediately in the event of a system contingency. This service will be available to all Transmission Customers that have a load obligation in the RTO-NE Market in accordance with Market Rule 1. The Transmission Customer may either supply this service with its own resources or through bilateral arrangements, or obtain the service through the RTO-NE Market.

The total of each category of Operating Reserve requirements for the RTO-NE Control Area in each hour is determined by RTO-NE in accordance with applicable RTO-NE System Rules.

The amount of and charges for Spinning Reserve Service will be accounted and paid for as part of the Operating Reserves pursuant to Market Rule 1.

The transmission service required with respect to Operating Reserve will be paid for as part of Regional Network Service, or Through or Out Service by all Transmission Customers and other entities that have a load obligation in the RTO-NE Market in accordance with Market Rule 1. The charge for Regional Network Service is determined in accordance with Schedule 9 to this OATT. The charge for Through or Out Service is determined in accordance with Schedule 8 to this OATT.

## **SCHEDULE 6**

### **OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE**

Supplemental Reserve Service is a service needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are online but unloaded, by quick-start generation or by interruptible load. This service will be available to all Transmission Customers that have a load obligation in the RTO-NE Market in accordance with Market Rule 1. The Transmission Customer may either supply this service with its own resources or through bilateral arrangements, or obtain the service through the RTO-NE Market.

The total of each category of Operating Reserve requirements for the RTO-NE Control Area in each hour is determined by RTO-NE in accordance with applicable RTO-NE System Rules. The amount of and charges for Supplemental Reserve Service will be accounted and paid for as part of the Operating Reserve s pursuant to Market Rule 1.

The transmission service required with respect to Operating Reserve will be paid for as part of Regional Network Service or Through or Out Service by all Transmission Customers that have a load obligation in the RTO-NE Market pursuant to Market Rule 1. The charge for Regional Network Service is determined in accordance with Schedule 9 to this OATT. The charge for Through or Out Service is determined in accordance with Schedule 8 to this OATT.

## **SCHEDULE 16**

### **SYSTEM RESTORATION AND PLANNING SERVICE FROM GENERATORS**

System Restoration and Planning Service are necessary to ensure the continued reliable operation of the New England Transmission System. System Restoration and Planning Service enables RTO-NE to designate specific generators interconnected to the transmission or distribution system at strategic locations capable of supplying load to re-energize the transmission system following a system-wide blackout. These designated generators are able to start without an outside electrical supply and are otherwise known as “Black Start Capable.” The planning and maintenance of adequate capability for restoration of the RTO-NE Control Area following a blackout represents a benefit to all entities using the power system. Therefore, this service must be taken from RTO-NE. In contrast to the System Restoration and Planning Service described herein, the actual supply of power that would allow a power producer to restart its own generating units may itself be self-supplied

or purchased from another power producer independent of the RTO-NE Control Area arrangements formulated by RTO-NE. The Black Start Capability intrinsic of System Restoration and Planning Service is to be provided by designated Market Participants through RTO-NE.

### **I. Rate Formulas**

A Transmission Customer purchasing Regional Network Service under Schedule 9 of this OATT shall be required to pay RTO-NE for its share of Black Start Restoration and Planning Service (“Black Start Responsibility”) as determined in accordance with the following formulas:

$$\text{MRSR} = \frac{1}{(\text{NL})}(\text{C})$$

Where:

MRSR = The Transmission Customers’ Monthly Restoration Service Rate.

NL = The aggregate of the individual sums of each Transmission Customer’s Regional Network Load for the billing month.

C = The sum of Ci for that month for each Black Start Generator, as defined in Section II below.

Each individual Transmission Customer’s charge in any billing month would be calculated by the following formula:

$$\text{MC} = (\text{MRSR})(\text{NL}_i)$$

Where

MC = The Monthly Charge.

NL<sub>i</sub> = The sum of a Transmission Customer’s Regional Network Load for the billing month.

A separate charge for this service based upon the above rates will be added to the Transmission Customer’s monthly bill.

### **II. Compensation to Generators**

**A. Eligibility.** In order to be designated as a “Black Start Generator” providing System Restoration Service and to be eligible for compensation under this Schedule 16, a generator must meet the following criteria

1. The unit is “Black Start Capable” in that it has the ability of being started without energy from other RTO-NE generating units in

such a way that it meets all of the requirements stated in Operating Procedure 11 (Black Start Capability Eligibility & Testing Requirements); and

2. The unit owner and RTO-NE agree that the unit should be designated Black Start Capable and accordingly is listed as a Black Start unit in Operating Procedure 11. Each generator which is eligible for and seeks compensation under the OATT for providing System Restoration Service shall execute an agreement with RTO-NE.

**B. Compensation.** A Black Start Generator shall be entitled to compensation in a month based on the following formula:

$$C_i = (\$Y/\text{kw-yr}/12) \times (\text{the unit's Monthly Claimed Capability for that month})$$

Where

“Y” = \$3.75 for the period from the effective date as determined by the Commission through and including December 31, 2003; \$4.00 for calendar year 2004, \$4.25 for calendar year 2005; and \$4.50 for calendar year 2006 and thereafter.

**C. Terms and Conditions.**

1. Generator Owner's commitment to provide System Restoration and Planning Service:

(a) Generators need to commit initially for at least three years to provide System Restoration and Planning Service from the date of the last black-start/system restoration study. A study is conducted each year.

(b) All succeeding commitments must be at least for three years.

(c) Generators may, and are encouraged to, commit to provide System Restoration and Planning Service for periods greater than three years with RTO-NE concurrence.

(d) Generators need to give at least one- year notice that they will no longer be able to provide System Restoration and Planning Service. This one-year notice cannot truncate the generator's commitment to provide System Restoration and Planning Service except as noted in item 1(e) or 1(f) below.

(e) If due to an event of Force Major a Generator Owner cannot provide System Restoration and Planning Service, the above notification requirements stated in items 1(a) and 1(b) are not binding.

(f) If an owner of a generation unit that is designated Black Start Capable decides to retire that unit, then the three year requirement to provide System Restoration and Planning Service from that unit is not binding. The one-year notice, however, is binding.

3. Performance obligations of generators that are providing System Restoration and Planning Service:

- (a) Generators that are providing System Restoration and Planning Service will be tested in accordance with Operating Procedure 11 or its successor, which may be revised from time to time.
- (b) Units that are providing System Restoration and Planning Service must start- up within the prescribed time stipulated in Operating Procedure 11 (Black Start Capability Eligibility & Testing Requirements). Not all unmanned units that are providing System Restoration and Planning Service will be asked to start- up at the same time.
- (c) If a unit fails a System Restoration and Planning Service test, the owner must incur the necessary costs to make that unit capable of passing the test within a reasonable amount of time. Until the unit passes another System Restoration and Planning Service test, it would not be compensated for providing System Restoration and Planning Service. All costs associated with System Restoration and Planning Service unit re-tests are at the owner's expense.

4. Obligations by RTO-NE to generators that are providing System Restoration and Planning Service:

- (d) Generators that commit to provide System Restoration and Planning Service will not have their Black Start Capable designation terminated within the time period of their commitment.
- (e) RTO-NE must provide at least one-year notice to the owner or owners of generation units that are providing System Restoration and Planning Service prior to terminating that unit's designation as Black Start Capable.
- (f) There are no additional restrictions on generation maintenance of designated Black Start Capable units beyond what exists for non-Black Start units except that designated Black Start generation units cannot take seasonal outages.

## **Appendix B**

### **Glossary:<sup>20</sup>**

#### **Ancillary Services:**

Resources that are used by the TSO/IMO to meet the reliability criteria of the network system. It includes those services that are necessary to support the transmission of energy from resources to loads while maintaining reliable operation of the transmission system in accordance with accepted electric industry practice.

#### **Automatic Generation Control (AGC):**

Equipment that automatically adjusts to changes in system frequency.

#### **Bilateral Contract:**

A contract between a supplier or seller of electricity (a generator, integrated utility, or marketer) and a purchaser or buyer of electricity (a load serving entity, an integrated utility, or a marketer) for delivery of a given amount of power at a contractually determined price.

#### **Black start Unit:**

A generation unit that has been certified by the TSO to be able to start up without an outside electrical supply.

#### **Co-optimization:**

Refers to the software formulation by which the products in the energy markets and ancillary services markets are evaluated and assigned in such a way as to satisfy the criteria that all products are dispatched at least cost, subject to any system constraints.

#### **Contingency:**

The unexpected failure or outage of a system component.

#### **Control Area:**

The geographic area comprising electric systems to which a common automatic generation control scheme is applied in order to match the power output of the generators within the system and the capacity and energy purchased from outside the system to the load within the system, while maintaining the frequency of the electric power system at proper limits at all times to ensure reliability.

#### **Day-Ahead Market:**

The market for energy or ancillary services run by an IMO that is for products offered one day (24 hours) prior to the day of operation. Those who offer products

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<sup>20</sup> For a Glossary of general terms used in the U.S. electric industry see <http://www.eia.doe.gov/cneaf/electricity/page/glossary.html>

that clear in the day-ahead market are financially obligated (but not physically required) to provide that product on the day of operation.

**Day-Ahead Prices:**

Day-Ahead Prices are those prices that result from the IMO's scheduling of resources that clear in the Day-Ahead Market.

**Energy Imbalance:**

Energy imbalance occurs when a difference occurs between the scheduled and the actual delivery of energy from a generator located within a Control Area over a single hour. Also known as 'load following service.'

**Forward Reserve:**

Forward Reserve is a product purchased by the IMO through an auction held one month and six months prior to the time the product is to be delivered to the market. It is similar to a call option on energy.

**Independent Market Operator (IMO):**

The entity charged with operation of the electric markets within a given control area. The IMO is independent, i.e., has no financial ties, from all market participants. An IMO cannot be a transmission owning entity nor a generation owning entity.

**Integrated Utility:**

An electric utility company that still owns or controls both generation resources and transmission resources.

**Load Serving Entity (LSE):**

An entity that has the responsibility to deliver energy and capacity to load or retail customers within a control area. This responsibility can be authorized by law or regulation, or it can be a contractual obligation or agreement. Such an entity can be a regulated distribution company, a municipal or cooperative utility, or an independent supplier, marketer, or aggregator.

**Operating Reserves:**

The electric capability above system demand that is available to the TSO within 10 to 30 minutes in the event of a contingency.

**Opportunity Cost:**

Generally, the cost of opportunities foregone. When providing reserves, generators face a lost opportunity to produce energy. The difference between what they could earn producing energy and any reserve payment provided to them is their lost opportunity cost.

**Reactive Power:**

Reactive power is a concept which describes the background energy movement in an Alternating Current (AC) system arising from the production of electric and

magnetic fields. These fields store energy which changes through each AC cycle. Devices which store energy by virtue of a magnetic field produced by a flow of current are said to absorb reactive power; those which store energy by virtue of electric fields are said to generate reactive power. Reactive power is measured in kVar.

**Reactive Supply:**

The injection or withdrawal of reactive power from generation units to maintain system voltages at the required level for system stability.

**Real-Time Market:**

Real-Time is a period (can be hourly or intervals of minutes depending on the market) in the current operating day for which the IMO dispatches system resources to provide energy and ancillary services.

**Real-Time Prices:**

The real-time prices are those prices that result from the IMO's dispatch of resources in the Real-Time Market in the operating day.

**Regulation:**

Provision of generation (or load response) that is subject to automatic controls that can be dispatched by the System Operator.

**Replacement Reserves:**

Reserve resources over and above Spinning Reserves and Supplemental (Non-Spinning) Reserves.

**Resource:**

Generation or load that is capable of providing an ancillary service.

**Self-Schedule**

Self-Schedule is when an entity commits and/or schedules its generation resource to provide energy or ancillary services regardless of whether that resource would have been scheduled or dispatched by the IMO through the market auction. Self-scheduling insures that a unit will run to provide service regardless whether the product is priced competitively in any market auction. Self-schedules are often the result of bilateral contracts between buyers and sellers.

**Spinning Reserve:**

Unloaded generation that is synchronized and ready to be available for use on the grid within 10 minutes of notification. It refers to reserve capacity that can be fully converted into electrical energy within ten minutes of notification from the IMO or TSO.

**Supplemental Reserve:**

That portion of Operating Reserves that is not Spinning Reserves (also known as Non-Spinning Reserve).

**Start-Up Costs:**

The costs of a generation unit incurred in starting up in order to supply energy to the market.

**System Restoration:**

The ability of the TSO, using Black start Units, to re-energize the system following a system-wide outage or blackout.

**System Services:**

Those services provided by the TSO to all participants in a control area. These services are Scheduling Pricing & Dispatch.

**Transmission Customer:**

An electric power customer that is directly connected to the transmission system. A transmission customer can be a load serving entity or a large end-use customer. Use of the term 'customer' in this paper refers to transmission customer unless otherwise identified.

**Transmission Owner:**

An electric power provider that owns transmission assets and makes those transmission assets available to the TSO in a given Control Area.

**Transmission System Operator (TSO):**

The entity charged with transmission system operation. The TSO is also charged with maintaining the reliability of the transmission system within a given control area. A system operator may or may not be the same entity as the market operator. A system operator can be either a transmission owner, an owner of a vertically integrated company (owning both generation and transmission), or an independent entity.

**VAR**

Volt Ampere Reactive is a measurement of Reactive Power used to meet the Control Area's requirement for Reactive power.

**Voltage Control:**

Voltage control is accomplished by managing Reactive Power through the use of devices that can control the magnitude and speed of reactive power response. Voltages must be maintained within an acceptable range in order to prevent damage to electrical equipment.

## **Appendix C**

### **Explanation of the terms used in the power balancing within UCTE region of Europe**

#### **1. National generating and purchase power capacity**

The national generating and purchase power capacity is the net maximum output capacity of energy utilities and of the power stations of industrial auto-producers of each country.

The net maximum electric capacities are obtained from the gross maximum electric capacities minus the electric station auxiliary power.

Power stations jointly operated with foreign partners are fully taken into account as national power capacity by that country where the power station is located.

If a power station is located at the frontier of two countries the share of each country is considered as national generating capacity.

The national generating and purchase power capacities are divided into hydro power stations, nuclear power stations, conventional thermal power stations, renewable energy sources and power sources that cannot be clearly identified.

Conventional thermal power stations also include gas turbines as well as industrial auto-producers and mining industry power stations which do not exclusively cover station auxiliary demand.

#### **2. Non-usable capacity**

Part of the generating and purchase power capacity indicated in the statistics cannot be freely deployed, such as:

- Capacity which cannot be utilized due to a temporary lack of primary energy, for instance
  - run-of-river power stations which, in the long mean, show low water supplies (hydraulic constraints) during certain seasons
  - tidal power stations
  - geothermal power stations
  - conventional thermal power stations with fuels that cannot be fully utilized, like unfit coal
  - oil- and gas-fired power stations with interruptible fuel supply
  - nuclear power stations in stretch-out operation
  - Lack of wind in wind power stations during certain seasons
- Capacity of hydro power stations which is subject to temporary limitations, such as
  - limited reservoir capacity, which does not allow the full power output to be

developed over periods of heavy load

- power losses due to high water
- loss of head height
- - Limitation of the flow downstream of the installation
- Capacity that cannot be transmitted because the necessary transmission capacity has not been scheduled (transmission constraints)
- Capacity in multiple purpose installations where electrical capacity is reduced in favor of other purposes, for example
  - heat extraction in combined heat and power plants
  - water debit for irrigation, navigation or tourism
- Power reduction caused by the cooling systems of power stations
- Capacity of power stations under construction whose commissioning is scheduled for a certain date, but capacity is not firmly available because of delays or retrofitting
- Part of capacity from power stations in test operation which are supposed to be not usable or which were effectively not usable
- Capacity in conservation which is commissioned only in emergency cases

In some member countries, the volume of non-usable capacity is not exactly known; therefore, the values for the different types of power stations should be estimated on the basis of statistics.

The non-usable capacity, e. g. of hydro or wind power stations, is obtained by comparing the power stations' connection capacity with the statistics of supplies from these power stations. To obtain reliable values for the power balance forecast, the TSO must have the necessary expertise in terms of hydro or aero-generation to analyze these statistics.

### **3. System services reserve**

The definition and utilization of power reserves differ from one country to the next. Nevertheless, the methodology agreed upon in this study for the total balance of the UCTE countries enables each country to take account of its own considerations in terms of power reserves.

The total reserve capacity required is intended to compensate for all possible differences in the power balance between the expected situation under normal conditions and the actual situation; it is thus intended to ensure a reliable and economic electricity supply. This reserve capacity is necessary:

- because the maximum load may exceed the expected value due to
  - meteorological influences, e. g. air temperatures below long-term average, cloudy sky
  - structural and economic influences and changes in consumption habits
- because part of the generating capacity is lower than expected according to the forecast owing to
  - availability of hydro power stations below the mean value

- above-average capacity subject to overhauls in thermal units
- above-average outages of generating units
- unanticipated requirements in terms of environmental protection
- outage of purchased power (industry and foreign partners).

The following distinctions are made as a function of access time and responsibility:

- seconds reserve for power-frequency control (primary and secondary control reserve) that is made available chiefly through the control band width of power stations operating under primary control (responsibility of the TSO);
- minutes reserve (warm reserve or spinning reserve) that is provided chiefly by storage stations, pumped-storage stations, gas turbines and by thermal power stations operating at less than full output (responsibility of the TSO);
- hour's reserve (cold reserve or stand-by reserve) available in thermal power stations which have to be started for this purpose (responsibility of the power plant operator).

Seconds and minutes reserve is provided in the framework of the "frequency control" system service by those power plant operators that have implemented, in co-operation with the TSOs, the necessary technical measures and have been bound by the TSO by contract to provide this reserve, and are called upon to make it available. Hence, this reserve is well known to the TSO.

Hours reserve is provided by the power plant operators. Reserves are activated as a function of the contractual arrangements concluded between customers and power plant operators, independently to a large extent of TSOs.

The reserve capacity considered as indispensable by the countries for system operation or the reserve effectively available is indicated in the forecast and in the retrospect as reserve for system services.

This reserve is made available by the internal system equipment only; it does not cover any losses pertinent to the contractual relationship between power station/customer.

The necessary additional reserve requires the most complex analysis. On one hand, the TSO controls primary, secondary and minutes reserve because, according to the national Grid Codes, he is responsible for the operational reserves, which are of decisive importance for the security of system operation. But in addition, this reserve component of the power balance methodology implies also long-term reserves for which system users are responsible in most countries, and which can be freely traded. In countries where a central Pool exists, this may also fall in the ambit of the Pool. The corresponding reserve demand must therefore be determined on the basis of information obtained from the power plant operators (or from the Pool) or, if this is not possible for competitive reasons, it must be estimated. These estimations can be carried out by using, for instance, statistics on program deviations of generation schedules and information about programs on reserve injections.

Owing to the aforementioned difference in responsibilities, a distinction is made in the power balance between the system operator's reserve for system services and the power plant operator's reserve. The system services reserve falls under the responsibility of TSOs and is hence completely known to them. Its amount is determined mainly on the basis of UCTE rules.

The volume of reserves for power plant operation as well as information on overhauls, outages and non-usable capacity is of particular importance in terms of competition: Information from power plant operators can hardly be obtained, except in the case of a central Pool. Therefore, the power plant operation reserve is integrated into the net power balance, i. e. the "remaining capacity".

#### **4. Guaranteed capacity**

The guaranteed capacity is obtained from the national generating and purchase power capacity after deducting all reductions in capacity and reserve capacities, i. e. non-usable capacity, overhauls and outages of thermal power stations as well as system services reserves. This capacity is firmly available to cover the load.

#### **5. Load**

The load of each country, also called reference load is recorded at the reference moment (3rd Wednesday of each month - 11:00 a. m., Central European Time) without taking account of power exports. It is measured at the high-voltage terminals of generator transformers and at substations. The sum of loads of the different member countries leads to the simultaneous aggregate load of the UCTE.

Normal climatic conditions, e. g. outdoor temperatures corresponding to the multi-annual average, and normal development of economic activities are assumed in the forecast.

In the retrospect, the load that was recorded at the reference moment has to be taken into account.

#### **6. Margin as against the monthly peak load**

In general, the effective peak load of a month is higher than the load measured on the 3rd Wednesday of each month at 11:00 a. m. This difference between the load recorded at the reference moment and the monthly peak load is indicated as a margin. It is given only as additional information about expected (according to the forecast) and effective (according to the retrospect) monthly peak loads; it does not influence the calculation of the internal surplus of available capacity

In the forecast, the countries indicate the additional demand in capacity they expect beyond the reference load at the moment of peak load, assuming normal outdoor temperatures and normal economic development.

The effective deviation between the monthly peak load and the reference load is indicated in the retrospect.

In some member countries, the effective monthly peak load is not known, but only the peak loads recorded on the Wednesdays of the month concerned.

### **7. Remaining capacity**

The remaining capacity is obtained from the guaranteed capacity minus the reference load.

The positive remaining capacity constitutes an export potential that is guaranteed to a large extent because most reductions in capacity and possible load increases within each country have already been taken into account for its determination in the power balance. But owing to the geographical extension of the UCTE network and possible transmission constraints it is not fully available at each point of the interconnected power system.

However, the power plant operation reserve is not included in the system services reserve. Therefore, it appears as part of the remaining capacity and of the export potential. The reserves intended to cover long-term power plant failures are not taken into consideration; the remaining capacity must therefore not be considered as a surplus capacity.

To obtain a realistic picture of the reliability of supply, of a possible surplus capacity or of the export potential, competent readers must carefully interpret the remaining capacity, taking account not only of imports and exports but also of possible strategies regarding power plant operation reserve and general reliability strategies of electricity traders with respect to their customers.

### **8. Guaranteed transportable capacities**

It can be imagined that in some countries transfrontier electricity exchanges will assume such a large proportion (e. g. in conjunction with an international electricity exchange market) that short-term international purchases and supplies will become extremely important for the power balance. In this case, a power balance that takes only account of imports and exports announced long in advance and known from schedules would not provide significant information. This may give rise, for instance, to a negative available capacity that would not reveal reliability problems but only the fact that large energy quantities are traded at short notice on international spot markets.

With a view to avoiding such situations, the TSO's concerned compile for each country a power balance leaving imports and exports out of account.

But already today, imports and exports reach considerable dimensions that are of decisive importance for the power balance and are likely to further increase in the future. Therefore, they must not be ignored in future power balances even though their estimation might be difficult. Thus, the surplus of available capacity within the UCTE will even gain in importance as the sum of all countries in the synchronous area.

These balances can be set up for the sum of UCTE countries and for groups of countries selected in accordance with technical network aspects (e. g. Iberian Peninsula, Italy, Balkans).

## Appendix D

### State of ancillary services (balancing services)

FINLAND									
Service Definition	Terminology	Provider	Notice to Deliver	Time to 100% Delivery	When can the TSO issue an instruction?	Mandatory or Commercial?	Procurement Mechanism?	Payment Mechanism?	Other info
Manually activated unsynchronized and synchronized energy capacity, that can be activated quickly to compensate for demand forecast errors and short term plant loss.	Secondary regulation, regulating power	Hydro generation, synchronized thermal generation or disconnectable load	No rule	5-10 mins	Any time	Commercial	Balancing Mechanism, by accepting a submitted bid and/or offer	Marginal price	From merit order list. Used for restoring momentary reserve. Sets the settlement price for balance deviation.
Manually activated active power reserve capacity to re-establish momentary disturbance reserve within 15 minutes (synchronized or fast-starting unsynchronized) or in balance management	Fast disturbance reserve	Hydro generation and unsynchronized gas turbine generation or disconnect	No rule	1 -15 mins	Any time	Commercial	Owned by TSO or annual bilateral contract	Annual fee Contracted with a competitive bidding procedure on yearly bases	Used for restoring momentary disturbance reserve. Has to cover dimensioning fault for each country.
There is no actual obligation for slow reserve in Finland	Slow reserve	Thermal power	6-48 hours (time of preparedness)	0-4 hour					Used for restoring the activated fast disturbance reserves

SLOVENIA									
Service Definition	Terminology	Provider	Notice to Deliver	Time to 100% Delivery	When can the TSO issue an instruction?	Mandatory or Commercial?	Procurement Mechanism?	Payment Mechanism?	Other info
Manually instructed synchronized energy capacity for frequency control in conditions of high rate of change of demand.	Primary reserve	Hydro and thermo generation	as soon as possible	30 sec	not instructed by TSO	mandatory	obligation	not paid	
Spare synchronized energy capacity to compensate for demand forecast errors and short term plant loss.	Secondary reserve	Hydro and thermo generation	30 sec	15 min after activation	automatic instructed (real time)	mandatory	invitation for tenders	regulated price	
Manually instructed un-synchronized energy capacity, that can be synchronized quickly, or demand that can be reduced, to compensate for demand forecast errors and short term plant loss.	Terciar minute reserve	Gas generation	15 min	10 min after activation	manually instructed	mandatory	invitation for tenders	regulated price	
Spare energy capacity to replace long term plant loss and demand forecasting errors.	contracted power reserve	contractor	1 hour	15 min to 1 hour		commercial	trade	market price	
Forward energy traded to reduce large energy imbalance volume.	energy balancing trading	trading party	1 hour	1 hour		Commercial	trade	market price	
Services required that can only be provided by another transmission system.	SO-SO contracted reserve power	Interconnect ed SO	0-24 hours ahead	15 min to 1 hour		Commercial	trade	market price	

POLAND									
Service Definition	Terminology	Provider	Notice to Deliver	Time to 100% Delivery	When can the TSO issue an instruction?	Mandatory or Commercial?	Procurement Mechanism?	Payment Mechanism?	Other info
Manually instructed synchronized energy capacity to compensate for demand forecast errors and short-term plant loss.	Hourly reserve	Generation	15 min	1-15 min	minimum 15 min before delivery	Commercial	Auction on the balancing market	pay as bid (energy only)	
Manually instructed un-synchronized energy capacity to compensate for demand forecast errors and long-term plant loss.	Replacement reserve	Generation	1-4 h	1-3 h	day ahead and within operation day	Commercial	Auction on the balancing market	pay as bid (energy only)	
Manually instructed operation of pumped storage power plants in emergency regime.	Emergency reserve	Pumped storage power plants	1-5 min	1-2 min	at any time within the operation day	Commercial	Bilateral contracts	contractual price (energy only)	
Manually instructed interchange of energy activated in emergency regime.	TSO-TSO contracted reserve	Neighboring TSO in synchronized operation and DC-connected TSO	negotiated (minimum 15 min)		minimum 15 min before delivery	Commercial	Bilateral contracts	contractual price (energy only)	

## **Appendix E**

### **Answers to Ancillary Services Questionnaires**

In total, answers to the two questionnaires were received from the following countries: Armenia, Bulgaria, Croatia, Czech Republic, Estonia, Georgia, Hungary, Kazakhstan, Latvia, Lithuania, Moldova, Poland, Romania, Russia, Slovakia, Turkey, and Ukraine.

A summary of the ERRA questionnaires in 2003 indicates that currently, ancillary services are treated in many different ways in the ERRA countries:

1. priced separately by regulatory authorities –Estonia, Georgia, Hungary, Lithuania, Romania, Russian Federation, Turkey;
2. priced separately by the market or bid/offers – Czech Republic, Poland ; and
3. not priced separately - costs are included in energy or transmission prices – Armenia, Croatia, Kazakhstan, Moldova, Slovakia, and Ukraine.

#### First Questionnaire:

Of the 19 full ERRA members, 13 members said that a transmission system operator (TSO) ensures the provision of ancillary services in their country. The vertically integrated utilities provide these services in the remainder of the countries. In those countries where a vertically integrated company is responsible for ancillary services such services are not priced separately rather they are rolled into the overall energy price. In 12 countries, the TSO is a legally independent company while other TSOs are still part of a vertically integrated company or are state owned or controlled.

Of the 13 countries where a TSO has responsibility for ensuring ancillary services, 8 countries have some separate pricing for these services; 6 countries apply cost-based pricing techniques and 2 countries use a market-based pricing scheme. The services that are most commonly priced separately are regulation/frequency response, voltage control, and operating reserves. Most countries are not yet part of any regional market for ancillary services.

#### Second Questionnaire:

Of the 12 responses received, the greatest number of respondents thought that ancillary services were important for ensuring system reliability and providing price signals to generators. Of the goals identified by the authors for ancillary services (establishment of competitive markets, ensuring system reliability, increasing operational efficiency, providing market transparency, and providing price signals to generators), nearly all respondents thought that separate pricing of ancillary services would help to accomplish those goals.

As noted above, in the majority of responding countries, a TSO or ISO has prime responsibility for the day-to-day operation of the energy markets and in most countries (10 out of 12) generation resources are dispatched in economic order (i.e., cheapest

resources are dispatched first). However, there are still a number of countries in which ancillary services are not priced separately. In these countries the ancillary service charges may be part of the transmission tariff or included in the electric generation price.

For those countries that do price ancillary services separately the tariffs are set mostly according to voltage level or customer class. For some countries though, these tariffs are just another component of the transmission tariff and set accordingly. Some countries incorporate peak/off-peak times for pricing as well. Almost all countries indicated that they have reserve requirements most of which are set by the TSO or ISO. In a few cases the reserve requirement is set by a vertically integrated company or through an administrative action.

#### Other information:

In Lithuania, ancillary services are a separate component of the transmission tariff and paid together with it since the expenses are mainly related to the generation sector which is not dependent on voltage level or usage. Also in Lithuania, the Ministry of Economy approves a grid code that identifies the reserve requirements using the N-1 criteria.

Hungary notes that the tariff for ancillary services depends on whether the customer is connected as a transmission customer or a distribution customer. Ancillary services are a necessary and unavoidable service, the cost of which must be covered by all customers in Hungary either directly (for eligible customers) or indirectly by public customers through the public suppliers. End-user tariffs contain this cost element.

Romania intends to treat ancillary services according to the UCTE norms.

Poland establishes ancillary service prices based upon negotiations and offers.

In Slovakia, RONI is preparing a study which will analyze costs for provision of ancillary services and will then issue a price list for each ancillary service based upon the results of that study.

Turkey bills ancillary services to the transmission system users – generators, eligible transmission customers, and distribution companies.

The TSO in Moldova is a state-owned company responsible for electricity transmission at high voltage. Moldova notes that it does not have separate pricing of ancillary services since most of its power (75-85%) is imported. It operates in a parallel regime with the system of Ukraine. Ancillary services are thus provided by Ukraine.

In the Czech Republic there is a Market Operator that calculates the price of energy imbalance according to processing the supply and demand balance of electricity supplies, evaluation of deviations i.e. differences between real (metered) and contracted electricity and settlement of deviations. There are two separated terms in the Czech Republic – Ancillary Services and System Services. **System services** (frequency control, voltage control, network control and operating margin) refer to the services essential to the proper

functioning of the power system which electricity utilities collectively provide for their customers in addition to the provision of electrical power, the supply of electric energy, and the transmission and distribution of this energy. The system services are provided by the transmission system operators through **ancillary services** (reserve—primary, secondary, tertiary, replacement reserve, black start, and reactive power) procured from the ancillary services providers. The Czech transmission system operator (CEPS) has its computing center and fund for ancillary services. The system services are provided by the Czech transmission system operator through the Market of ancillary services established in 2001. In 2003 the ancillary services such as primary, secondary and tertiary regulation, quick start, and replacement reserve were offered there.

Also, in the Czech Republic, the charges of ancillary services such as primary and secondary regulation have only a demand component (kW) others (tertiary regulation, quick start and replacement reserve) have both components. All system services charges have only an energy component (CZK/kWh) according to volume of consumption. Transmission tariffs are divided into two types of network charges; **connection charges** and **system services charges**. The transmission system operator (CEPS) pays the costs of ancillary services to the providers of such services and users pay TSO a system services charge in respect of these costs. Costs of these services and cost related to maintenance of TSO are summarized and reflected in the transmission system operator's fee controlled by the independent regulator. System services charges are paid to the CEPS by consumers neither directly (eligible consumers from transmission system) or through regulated distribution charges (eligible and ineligible customers).

Croatia notes that the TSO function is given to the Independent System and Market Operator which is the subsidiary of the state electric utility (HEP). Under the Energy Law, the subsidiary is scheduled to become legally independent by a transfer of shares to the Government.

In Georgia, the TSO is a legally independent company responsible for all the functions of transmission and dispatch. Tariffs for transmission and the dispatch of electricity are set separately. Transmission tariffs depend on the voltage and customer group whereas tariffs for dispatch are the same for all customer groups. The tariffs are calculated based upon the full cost of service. Technical parameters and obligations for maintenance are set out in the license attachments for both.

Ukraine sets a special price for ancillary services but it is a component of the electricity generation price. Ancillary services are compensated through the electricity wholesale market price. In the wholesale price, the electricity supplier pays additional charges to the generators. These charges are related to changes in the mode of the system. A pricing mechanism has been introduced that adjusts payments based upon actual grid operations. Marginal hourly bid prices submitted to the system operator have been abolished. Bids based only on variable costs have been introduced. Additional payments are made to generators that ensure reserve capacity and to units whose load increased in accordance with system requirements. Units with cyclic-load capability are paid in order to motivate units to load at low cost hours.



## **Appendix F**

### **Questionnaires**

The following questionnaires were sent to the ERRA members:

#### **Questionnaire I.**

***Who is responsible to ensure ancillary services in your country?***

- Vertically integrated energy company
- Transmission system operator (legally independent company)

***2. Who is a real provider of ancillary services?***

- Legally independent generators
- Generators owned by system operator
- Others , please indicate

***3. What is legal status of TSO in your country?***

- Department of vertically integrated company
- Subsidiary of vertically integrated company
- Daughter company of vertically integrated company
- Legally independent company
- Others, please indicate

***4. What kind of pricing of ancillary services is present?***

- Market based
- Regulated cost based approach
- There is not separate pricing for ancillary services (all is include in energy price)

***5. What kind of ancillary services are priced in your country?***

- Regulation and frequency response
- Reactive supply and voltage control
- Energy imbalances
- Operating reserves
- Black start service
- Others, please indicate

***6. To whom all or part of ancillary services are charged to (bill issued)?***

- Distribution system operator's
- Eligible customers
- All customers

**7. On your mind what is rationale for introducing pricing of ancillary services?**

- Increase of operational efficiency
- Cutting of energy demand curve
- Introducing of demand orientated pricing
- Others, please indicate

**8. Does service provider (TSO's or others) offer's ancillary services in regional market?**

**9. Please provide any other comments or questions regarding the topic of Ancillary Services as covered in the Issue Paper that are relevant to your country or Commission."**

**Questionnaire II.**

We would like to thank everyone for responding to our last set of questions. One thing we learned is that there is no consistent treatment of ancillary services in the ERRA countries. As a result this is a difficult topic and one that creates significant confusion among ERRA members. Here again is a brief summary of what we learned in the last questionnaire.

Of the 19 full ERRA members, 13 members said that a transmission system operator (TSO) ensures the provision of ancillary services in their country. The vertically integrated utilities provide these services in the remainder of the countries. In those countries where a vertically integrated company is responsible for ancillary services such services are not priced separately rather they are rolled into the overall energy price. In 12 countries, the TSO is a legally independent company while other TSOs are still part of a vertically integrated company or are state owned or controlled.

Of the 13 countries where a TSO has responsibility for ensuring ancillary services, 8 countries have some separate pricing for these services; 6 countries apply cost-based pricing techniques and 2 countries use a market-based pricing scheme. The services that are most commonly priced separately are regulation/frequency response, voltage control, and operating reserves. Most countries are not yet part of any regional market for ancillary services.

Here are a few more questions we would like you to answer:

1. Do you think the treatment of ancillary services is important for:
  - (a) Establishment of competitive markets
  - (b) Ensuring system reliability
  - (c) Increasing operational efficiency

- (d) Provide market transparency
  - (e) Provide price signal to generation
  - (e) All of the above
  - (f) Other
2. Do you think separate pricing for ancillary services would accomplish some of the goals in question #1?
    - (a) Yes
    - (b) No
  3. Does your country have an Independent System Operator or Market Operator that has responsibility for the day-to-day operation of your energy markets?
    - (a) Yes
    - (b) No
  4. Does your system operator (TSO or Market Operator or Company) dispatch generation based on an economic hierarchy (cheapest sources are dispatched first – load curve is optimized according to price of generation)?
    - (a) Yes
    - (b) No
    - (c) I don't understand the question.
  5. For those countries with separate cost-based pricing for ancillary services, are tariffs set according to:
    - (a) Voltage level
    - (b) Customer class or group
    - (c) Other (explain)
    - (d) I don't understand the question.
  6. Is there a reserve requirement set in your country, either for the whole country or for sub-regions?
    - (a) Yes
    - (b) No
    - (c) I don't understand the question.
  7. For those countries that have reserve requirements, which entity sets the level of reserves needed to maintain system reliability?
    - (a) TSO
    - (b) Vertically integrated company
    - (c) Regulatory authority
    - (d) Other (explain)
    - (e) I don't understand the question.
  8. What topics were covered in the Ancillary Services paper that requires further explanation? Please list.

9. What topics were not covered in the Ancillary Services paper that you would like to see addressed? Please list.
10. Here are some questions that you raised in the first questionnaire. We will try to answer these in our revision to the paper.
  - a) What method can be used to determine the cost of ancillary services?
  - b) How do you calculate the price of energy imbalances?
  - c) How do the ancillary services described in the paper relate to primary, secondary, and tertiary services provided in other countries?
  - d) Do some ancillary services charges have both an energy component and a demand component (kWh and kW)?
  - e) Which component of electric service usually includes the ancillary services costs – energy, transmission, or distribution?
11. Please list below any other questions you would like us to answer in the paper.

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